860626 S.P.N.L.A.

COMPUTERS -- TO INCREASE THE VALUE OF TEMPERATURE LOGS

BILLY P. MORRIS*
R. D. COCANOWER*

ABSTRACT

Temperature logs have been utilized to gain information on fluid movement in and adjacent to well bores for many years. Much research, both field and laboratory, has been done in an attempt to apply mathematical standards to the information obtained. Detailed quantitative interpretation has been generally unsuccessful because of local geology, bore hole effects, unstable well conditions, and the time required to approach thermal stability. The application of the temperature log to injection profiling has focused our attention on these problems more pointedly.

The technique discussed in this paper provides a means of investigating injection strata more thoroughly and minimizing the well condition influence. A digital system is employed, recording a series of runs on tape at predetermined time intervals. The tapes are programmed through a computer to establish the temperature decay rate through selected intervals in the well bore. When the rate is established, an extrapolation data provides an accurate progression toward thermal equilibrium in the strata. This data is used to determine the fluid acceptance profile. For further analysis of data, a differential is available for any selected interval.

Field examples are presented comparing the various temperature logging techniques with the computerized logs to further demonstrate the validity of the information obtained.

INTRODUCTION

Temperature logs are one of the oldest means of investigating downhole conditions. Many new applications and methods of interpretation of results have been developed, most of them valid to a limited degree. These "new" premises and techniques are, for the most part, extensions of, or improvements upon prior work. Supporting information, both theoretical and actual, lend credence to some individual histories, which are then accepted as the "standards" for their particular approach. Our ability to compute results from physical data has improved almost without bounds, and some highly sophisticated data calculations has evolved. The advancement in this area has pre-supposed that the methods of gathering and extracting these basic data has kept pace with our analytical ability.

*The Western Company, Midland, Texas
*The Western Company, Fort Worth, Texas

Unfortunately, such is not the case. We still must work with information collected by, basically, a thermometer in a very restricted environment, the well bore.

These "thermometers" have been improved radically, and in our zeal to get to the final answer, we tend to impute capabilities to the tools that cannot exist under the conditions in which they operate. We then supply the missing data from our individual understanding of the conditions and our opinions are "read in" to the log as actual recorded data. The results computed from this information are as varied as the number of qualitative "facts" we supply.

The widespread differences in temperature log interpretation indicate that we should re-examine the raw data and attempt to validate the basic components of our formulations.

The total amount of temperature information available to us at a given time exists in the absolute temperature curve (Figure 1); therefore, we must devise a method to extract this data, then determine what condition affected it. To do this, an understanding of the tools, their reactions and methods of recording, and the environmental reactions surrounding them is imperative.

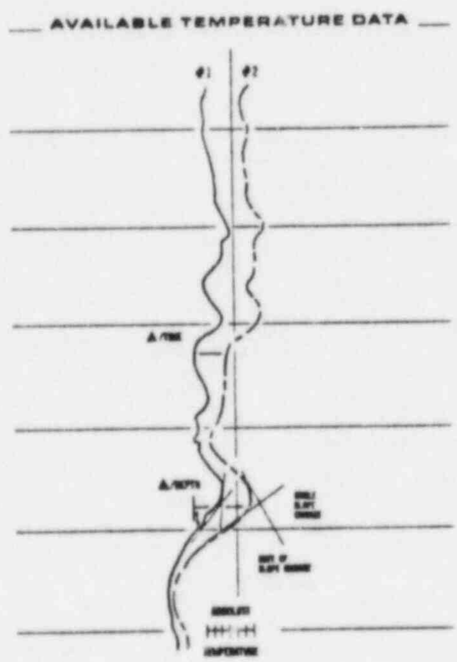


Figure 1. Absolute Temperature Curves

TOOLS

Surface recording tools can be divided into three basic classifications:

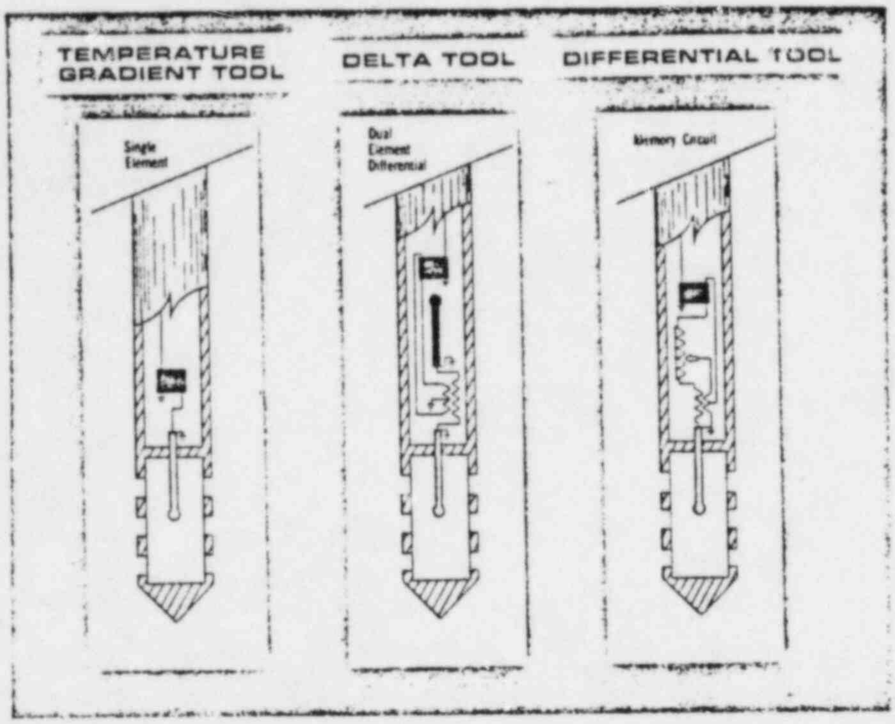


Figure 2. Basic Temperature Tools

1. Absolute or normal temperature: A single element tool, calibrated and aligned to detect the existing temperature downhole and transmit this information to the surface, where it is recorded as actual temperature versus depth.

   This tool measures the temperature of the borehole fluids at a single point and is subject to the total of the vertical as well as lateral effects of temperature transition zone. Sharp definition of temperature interfaces is improbable unless the differential is extreme, and slight changes often go unnoticed unless recording sensitivity is high. Total transition from one temperature to another is usually averaged over a long vertical interval.

2. Temperature Differential: The differential tool utilizes two elements physically separated by a given distance. Both elements detect the absolute temperature of the fluids at their respective depths. These temperatures are impressed upon a "comparison circuit" and the difference between them is transmitted to the surface and recorded. Hence, if one element

detects 76 degrees and the other, 5' above it, registers 75 degrees, a 1 degree progression for the interval is recorded. As long as this progression remains the same as the tool is moved downhole, no further deflection is recorded, but should the rate of change increase to 2 degrees per five feet interval (i.e. top element 78 degrees and bottom 80 degrees) an additional one degree deflection would appear on the recording for the given interval.

The two element tool can be calibrated and used as a "true differential" indicator by taking stationary readings. The actual difference in temperature would be determined by the deflection. During most logging operations, the progress downhole is usually continuous; therefore, both the rate and the amount of temperature change affect the readings, and the log is used as a relative temperature change indicator. The actual temperature is recorded simultaneously on a separate circuit. The advantage in this usage is a more prominent indication of temperature change over a given interval.

3. <u>A - Priori "Differential":</u> This principle simulates the differential effect by using a single element and an electronic "memory circuit." The single element detects the temperature of the well fluids and sends this information to a memory cell or delay circuit. After a pre-selected time this temperature impulse is fed back into a "comparison circuit" and is impressed with the impulse currently generated by the temperature element. The difference in temperature detected at the two time-intervals is recorded as differential.

   This tool is not a true differential indicator with respect to depth since it depends upon movement for its depth spacing. Theoretically, the spacing is controlled by logging speed, but in actual practice, the time delay for feed back in milliseconds and normal logging speeds are not compatible. No consistent spacing control is possible without electronic "gateing" keyed to the depth meter. Continuous movement again incurs effect from both the rate and amount of temperature change, and confines the use of this curve to an instantaneous slope change indicator. As with the other differential tools, the actual temperature is recorded on a separate circuit. The downhole tool used in the A-priori method is only the normal or absolute temperature sonde. All the delay circuits are in the surface instrumentation. NOTE: The electronic description in the foregoing discussion is not technically correct, but has been simplified to emphasize the sequence of occurrence and reaction.

APPLICATION

Temperature analysis is useful in four separate applications. All the interpretations have overlapping variations.

1. <u>Definition of long enduring effects,</u> such as cement top location. Timing is not critical since the heat evolved by cement reaction is continuous for some time and relatively slow to dissipate. Good definition is possible for long periods of

time after operation. Absolute temperature tools are competent for this work, as anomalies are usually quite pronounced.

2. Production Logging. Location of production entering well bore. Identification of channels when produced fluids cause changes in ambient temperatures. Differential tools assist in interpretation and definition of slight changes of temperature.

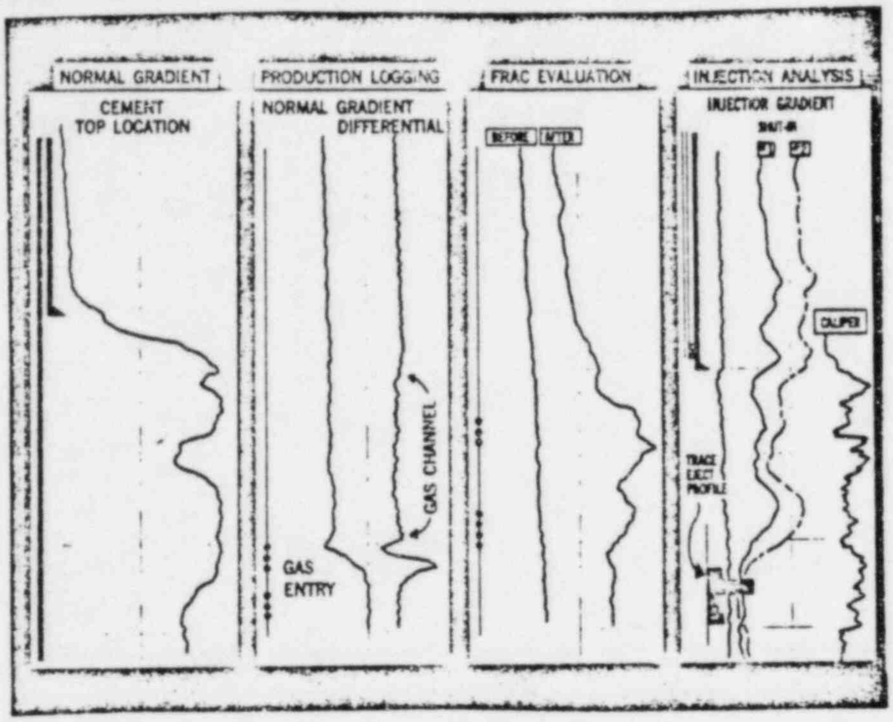


Figure 3. Temperature Analysis Applications

Thin zones of production entry can be better defined with short spaced investigation.

3. Frac or Stimulation Evaluation. Identification of short term temperature effects. Zone identification is made by comparison of normal gradient curve before operations to the anomalies induced by pumping fluids downhole. Temperature effects are comparatively short lived and time is rather critical. Interpretation will vary with the direction of induced anomalies (heated or cooled) and with the treating fluids used.

Absolute temperature sonde must be used but the differential curve can assist in defining limits of zones, especially when differentials from normal gradient are small.

4. Injection Analysis. Identification of zones of injection by observing the changes in well bore temperatures induced by injection, and comparing the relative rates of recovery opposite various strata when injection is discontinued. The absolute temperature tool must be used for valid interpretation, and the differential tool may be used for upper and lower limits of zones.

ENVIRONMENTAL EFFECTS

All temperature analysis is accomplished by observing the reaction when ambient temperatures are disturbed by some means, resulting in down-hole temperatures other than normal gradient. The gathering points for all temperature data are confined to the well bore and all measurements must be considered from these indices only. Reaction in the formation is inferred from its effect on the well bore temperatures.

The temperature curve is a graph of temperature versus depth within the borehole. As such, it considers only two moments -- vertical and lateral - but the effect of all the conditions surrounding the data point dictates its temperature at any given time. Since the temperature observed at a specific point is the result of its total environment, a method of defining the variables and eliminating or computing their effect is necessary before valid quantitative work can be accomplished.

The definition must be done with the raw data derived from the temperature curve, which is subject to the inherent limitations of the collecting process. A better understanding of these limitations can be established when we examine the basic principles involved. (Figure 4).

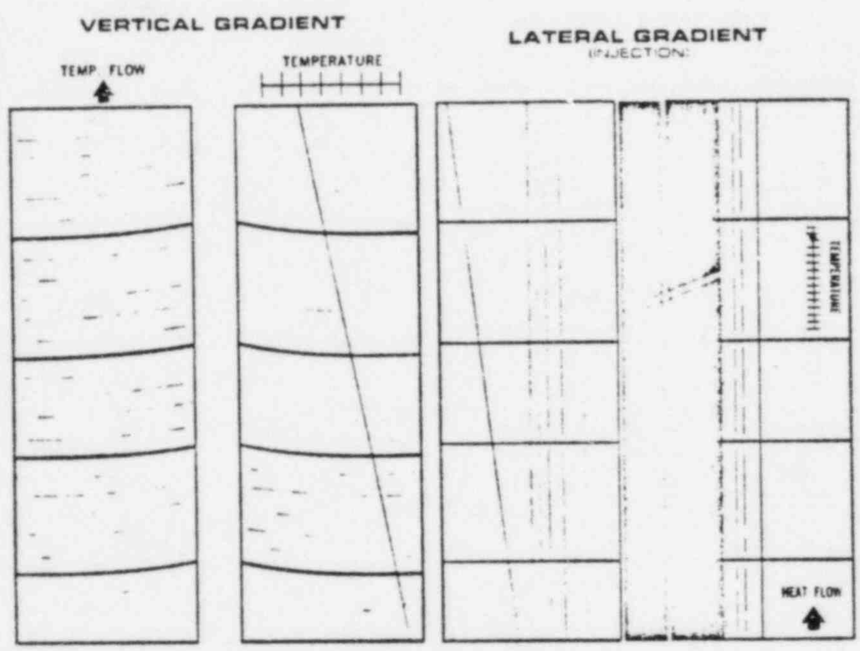


Figure 4. Vertical and Lateral Effects

The geothermal gradient is caused by the continuous flow of heat outward from the interior of the earth. The flow of heat is an equilibrium process between the heat sources, the conductivities of the transmitting material and the temperature differential between two points; therefore, there is no accumulation of thermal energy in the path of heat transmission. The thermal gradient for a given medium is dependent upon its conductivity.

The normal gradient of a given formation is not appreciably disturbed by the existence of a hole or well since the differential still exists vertically, and the ambient temperature at any given depth remains the same throughout the strata. This provides an infinite reservoir of heat at the existing temperature for a given depth, which can be recorded by the absolute temperature tool. (Normal Gradient Curve).

Injecting cooler fluids into the well bore causes a differential to occur between the well and the reservoir of heat at any given depth, and the equilibrium process is established immediately, forming a horizontal gradient at that depth. Assuming injection conditions (rate and temperature) to remain constant, a constant rate of heat replacement is established that is dependent upon the formation to borehole differential and the conductivity of the medium between the two temperature extremeties.

Since the rate of heat flow is constant for these given conditions, steady state heat flow is approached after the initial injection period, and thermal equilibrium with the ambient formation temperatures is established at some radius from the well bore (Figure 5). Continued injection results in no further measurable cooling of the well bore or formation around it, and the rate of heat absorption by the water becomes constant for each depth. Therefore, the well bore gradient is established as a near constant progression at some temperature cooler than normal formation gradient.

The zone or zones of fluid entry can sometimes be recognized by the slight slope change at the top of the injection interval but close definition of the zones under injection conditions is improbable unless considerable vertical separation between zones exists (strata cooling between injection zones discussed later.) The injection zones have an additional effect imposed. The fluid entering the zone at some temperature less than ambient formation temperature, not only cools the formation face by passage, but the reservoir of heat is displaced to an ever-increasing radius from the well bore by the fluid. Since the fluid in the borehole is the coolest in the system and the well bore is the collection point for the temperature data, no additional cooling is recorded at this depth as a result of continued injection.

After these conditions have been established, the recorded injection temperature gradient in the well bore remains essentially constant throughout the total period of injection, and a gradient curve run under injection conditions will reflect only the temperature of the injection fluids at their respective depths. The result is a gradient curve of relatively constant progression, depressed by some degree cooler than normal formation gradient. The two temperature extremes have now been

established and the conditions are at steady state.

When injection is discontinued, the well bore to formation differential still exists. The water is no longer moving, and the equilibrium process attempts to bring the fluid in the well back to the ambient formation temperature at each depth.

The conductivities of each strata allow a characteristic rate of heat replacement at their depth, and the relative rate of heating is not equal for each zone. The rates of heating at various levels differ but are proportional for each zone with respect to conductivity and differential at any given time.

The result in the well bore is a progressive, proportional heating at all depths except the interval that has accepted the injection. This interval has not only been cooled to the thermal equilibrium radius, but the reservoir of heat has been displaced from the bore hole to the point that lateral or horizontal flow of heat to the well is either effectively blocked, or is radically decreased.

Any replacement of heat at the points opposite the injection zones must come from above or below the strata, or be delayed until the fluid bank in the formation is warmed to the degree that it will, in turn, transmit heat to the well bore fluid. These variances in recovery rate can be identified by a temperature traverse of the hole with the absolute temperature tools. Several traverses at selected time intervals after shut-in reflect these relative rates and a DT with respect to time is evolved for each interval. As previously stated, these relationships are proportional except over the zone of fluid entry. These progressive or "decay series" curves can be used for qualitative identification of injection zones. Identification of the true injection incurred anomalies is not always simple, since many conditions can affect the recovery rate observed in the well bore. (Figure 6).

Mechanical conditions such as casing, tubing, hole size and cementing programs behind casing, changing bore hole size, thin zones widely separated, or closely spaced, or any other than uniform physical conditions can cause variations in well bore heat replacement rates. A sufficient number of subsequent traverses must be made to identify the true injection zones.

Theoretically, once the zone is identified, the DT with time established after recovery of the injection zone commences can be used for quantitative calculation of percent fluid intake per interval.

This application, used without other control data, assumes several hypothetical conditions:

1. Each strata is thermally independent of adjacent formations.
2. Vertical heat interchange between strata and within the bore hole is negligible.
3. The heat flow effects precisely reverse themselves during the recovery period.

Graphic examination of the sequence of thermal transfer will reveal that these effects must be considered in any quantitative work.

Figure 5

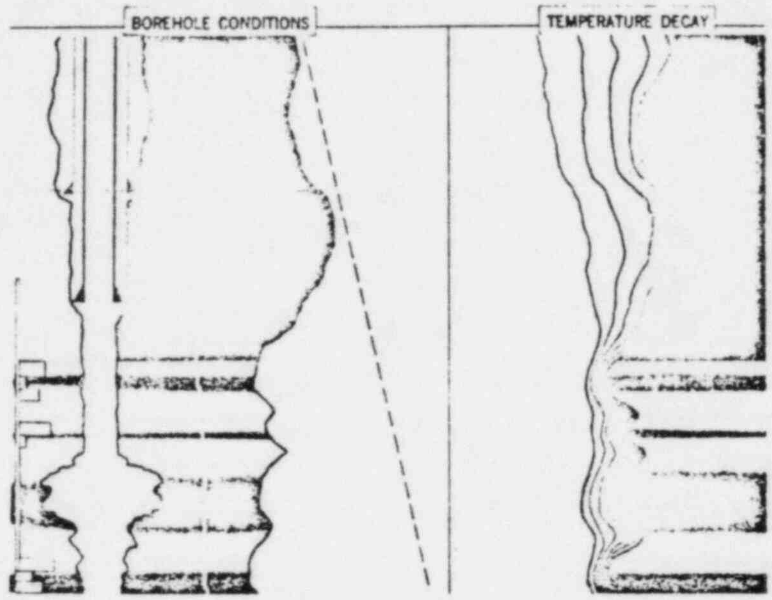


Figure 6. Conditions Affecting Recovery Rates

THEORY AND VARIATIONS

The many attempts at quantitative evaluation of injection well temperature logs have evolved an approach that is closely analogous to the radial flow pressure decline calculations, which assume only two dimensional flow. The application to thermal evaluation considers individual strata, with the cooling approaching the ideal or complete thermal equilibrium at an infinite radius. Figure 7-A.

At the initiation of injection, the radius of cooling is slight (T_1), increasing throughout the period of injection to the ideal temperature distribution (T_6). This progression is assumed to be independent of boundary temperature effects. Figure 7-B illustrates the temperature distribution in adjacent strata under this assumption.

Theorizing that temperature flow effects precisely reverse themselves upon interrupting injection allows calculation of the rate of recovery within the well bore. Relating this recovery rate to the heat transfer co-efficient of the formation, period of injection, total injection volume, and ambient to injection temperature differential, a formula can be evolved that should indicate the injection distribution.

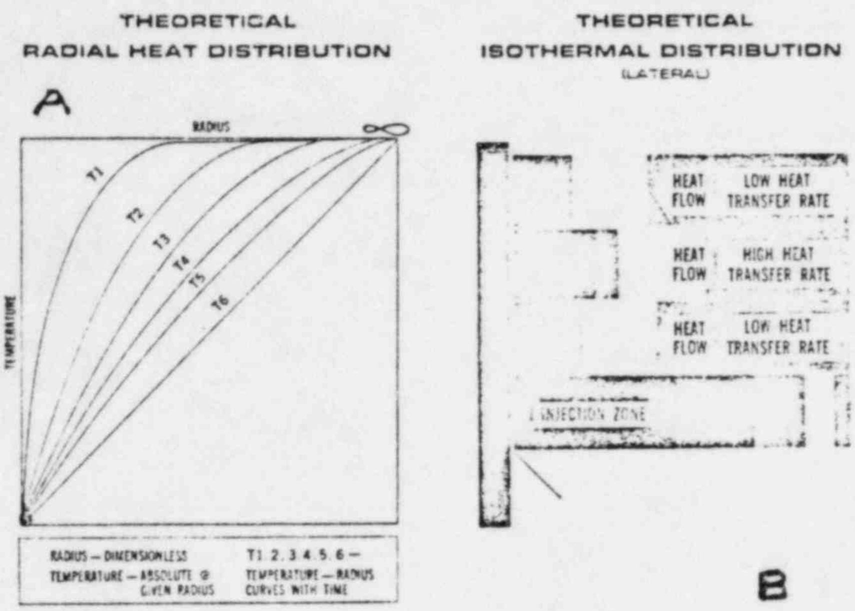


FIGURE 7.

The mechanics of heat flow are not limited by vertical permeability boundaries as are pressure or fluid flow effects; therefore, this approach toward evaluation must be modified to consider the effects of heat flow within the formation upon the well bore temperatures.

The constant proportional progression of heat distribution through a given strata which must be assumed quantitative evaluation does not actually exist. Figure 8-A illustrates the complexities of heat flow mechanics by joining the center points of the isotherm distribution of Figure 7-B.

It becomes apparent that as the vertical heat differential between strata not accepting fluid becomes more pronounced, a greater amount of heat is taken from the adjacent strata to attempt local equilibrium. These effects become self-limiting, and disrupt proportional cooling progression of individual strata. For practical interpretive uses, the cumulative cooling is fixed at some finite radius. Figure 8-B.

This radius cannot be established as a constant for a given formation without also considering the strata thickness, since a thin formation will be more affected by the adjacent temperatures than a thicker one. As a result of these reactions, a calculation based upon the radial flow principle must consider additional control data to become accurate. The premise of precisely reversed recovery effects is also invalid for calculations. The zones do not reverse the heat flow but the reactions observed in the well bore are reversed, with limitations.

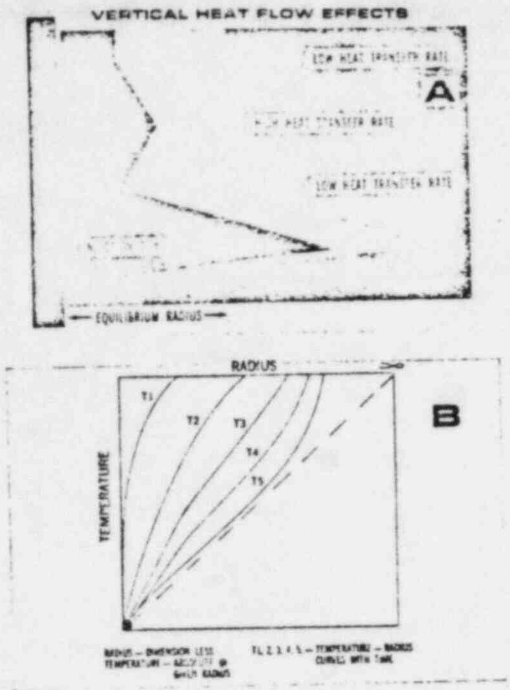


Figure 8. Complexities of Heat Flow Mechanics

The steady state heat flow approached during injection cannot be established during shut-in since there is no heat carried away under static fluid conditions. The rates of recovery observed in the well bore constantly diminish with the decreasing temperature differential until recovery to ambient formation temperature is effected. The resulting isothermic distribution sequence is depicted in Figure 9.

As injection is interrupted, only slight vertical differential exists between strata in the proximity of the well bore, but the well to ambient formation differential is at its maximum. Lateral heat flow from the formation to the well is at peak rate and very slight vertical heat inter-change occurs near the well. During the collapse of the heat sink, or cool cell, the recovery of the more conductive formations surpasses the slower conductive strata, and a temperature differential develops between zones, establishing a local equilibrium process near the well bore.

The formations of lower transmitting efficiency are then warmed by vertical, as well as lateral heat flow, and in turn, affect the well bore fluids. Since all the temperature data is gathered from the well bore, these effects obliterate the lateral recovery rate data needed for quantitative calculations.

The period of maximum lateral, and minimum vertical effect on the well bore temperature is transient, occurring during the initial recovery process after shut-in. The recovery rate data must be collected during this "optimum time" period when the rates more nearly approach the lateral

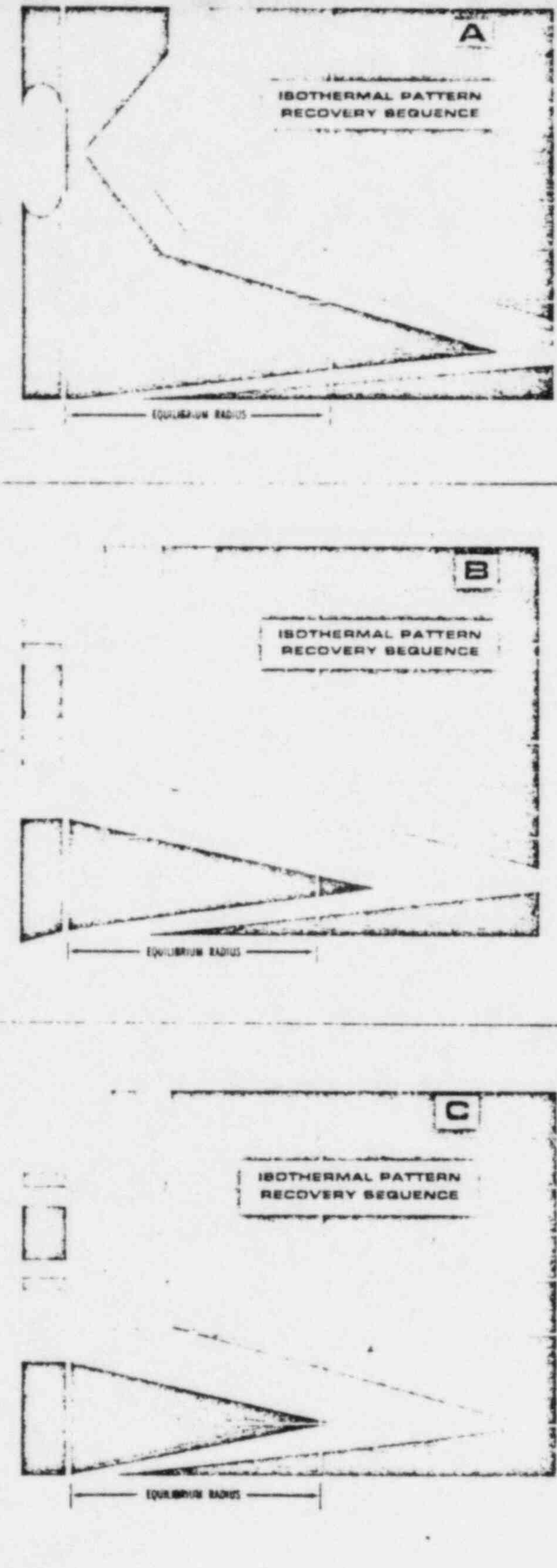


Figure 9. Isothermal Pattern Recovery Sequence

flow characteristics necessary for valid calculations.

These initial data may be extrapolated through the time interval where distortion occurs to the total recovery point, or ambient formation temperature. The extrapolated rates then reflect the true lateral recovery characteristics, relatively independent of vertical flow effects. Projection of these data from injection temperature to indigenous formation temperature will identify the zones that have accepted injection, since their proportional recovery rate has been interrupted. (Figure 10).

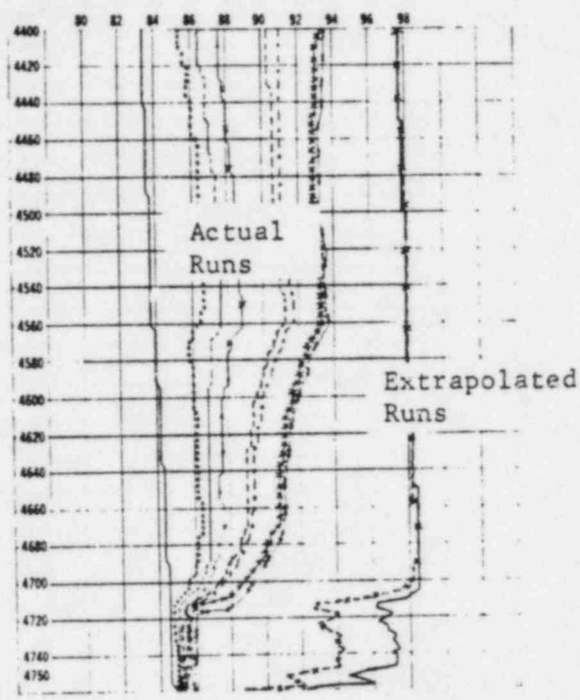


Figure 10. Actual versus Extrapolated Progression

The source of heat required for proportional recovery has been displaced past the thermal equilibrium radius by the injection fluid, and does not contribute a lateral flow of heat to the well bore during the inspection period (logging time duration). Figure 11.

Heat for recovery opposite the injection zones must be supplied vertically from adjacent strata. These formations have been cooled by proximity to the injection zone and cannot contribute heat flow at normal formation temperature. The source heat for recovery is less than ambient formation temperature; therefore, proportional extrapolations, based on decay data, cannot approach gradient temperature at these depths.

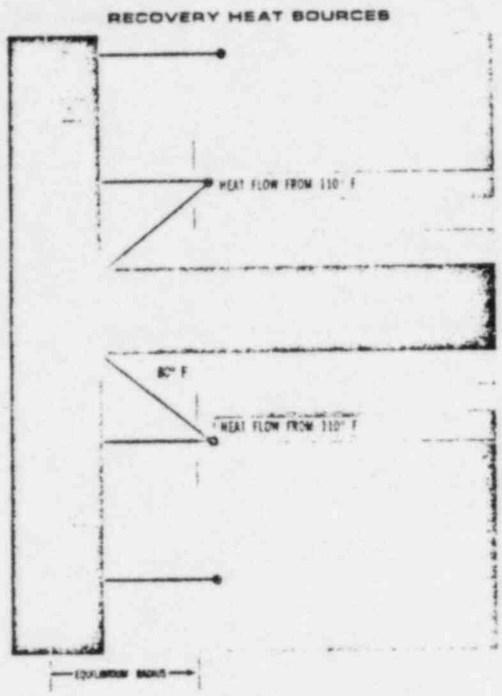


FIGURE 11.

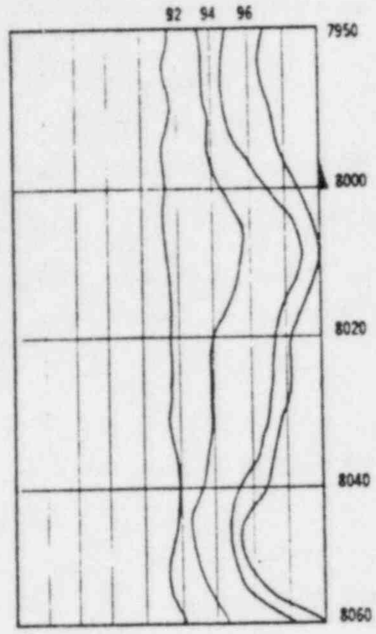
An example of this first basic extrapolation step is shown in Figure 12. The average DT with time from three runs is used for brevity in explanation rather than the proportional extrapolation that must be used for true quantitative work.

Through the 84 hour extrapolation based on 2 hour decay time, the deepest point to equal normal gradient is 8030 (118.5 degrees). All points above 8032 were eliminated from the next extrapolation at 95 hours. Temperatures from 8057 to TD were also equal to normal gradient and eliminated as injection zones.

The 95 hour extrapolation eliminated the zones from 8032 to 8040 and the 2' interval from 8055-57. A thin zone from 8047-49 exceeded the gradient temperature at 327 hours and the ratio of progression of the two remaining zones indicate that extrapolation to normal gradient would require an unrealistic time, even considering an average DT with time.

The remaining temperature differences at four inspection depths were prorated to percentage injection in these zones. The assignation of these percentages must be modified by the effects of zone cooling and zone thickness in multi-zone injector.

Figure 9 depicts a single zone of injection bounded on both sides by non-injection zones. Multi-zone injectors must consider strata not accepting injection sandwiched with zones which have had the indigenous heat reservoir displaced by injection water.



COMPUTER EXTRAPOLATION

91.8	96.0	0.50	117.0				117.0		
91.8	96.0	0.55	117.0				117.1		
91.8	95.8	0.44	112.6				117.3		
91.8	95.9	0.50	116.9				117.4		
91.8	96.0	0.55	117.5				117.5		
91.8	95.7	0.35	110.4				117.6		
91.8	95.6	0.35	110.3				117.8		
91.9	95.4	0.25	109.9				117.9		
91.8	95.4	0.40	112.2				118.0		
91.8	95.4	0.40	112.2				118.1		
91.8	95.3	0.35	110.0				118.3		
91.8	95.3	0.35	110.5				118.4		
91.8	95.6	0.55	118.5				118.5		
91.8	95.2	0.30	107.8	109.5			118.6		
91.8	95.3	0.40	112.1	114.4			118.8		
91.8	95.3	0.40	112.1	114.4			118.9		
91.9	95.4	0.50	116.4	119.0			119.0		
91.9	94.7	0.10	98.9	99.5	102.1	111.1	119.1	8.0	13.9
91.9	94.3	0.05	96.4	96.7	98.2	102.7	119.2	16.6	28.8
91.9	94.8	0.15	101.8	102.6	106.7	119.7	119.4		
91.9	94.5	0.05	96.6	96.9	98.4	102.9	119.5	16.4	26.6
91.9	94.5	0.05	96.6	96.9	98.4	102.9	119.6	16.5	26.7
91.9	94.9	0.25	105.4	106.7			119.8		
91.9	96.0	0.75	119.9				119.9		
91.9	96.4	0.85	120.0				120.0		

Figure 12. Trial Extrapolation-lateral Only

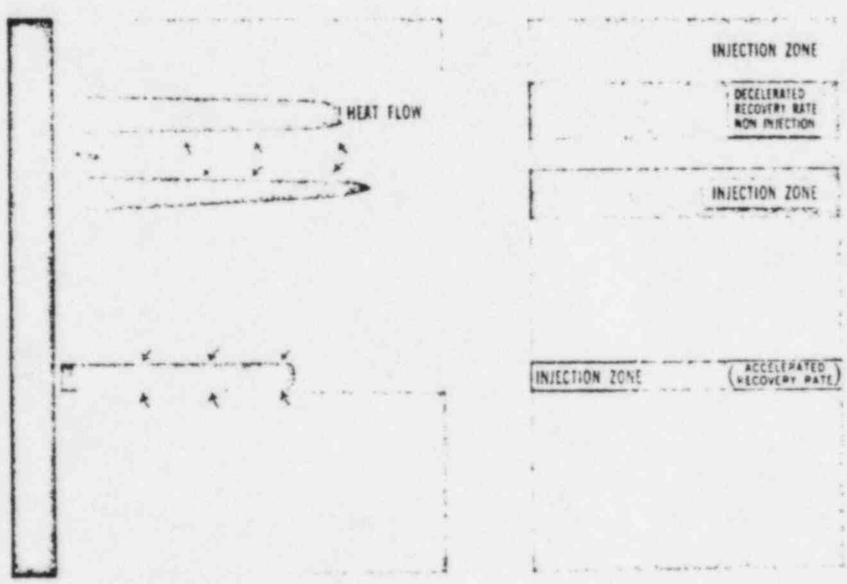


Figure 13. Comparison of Recovery Rates

These formations are effectively isolated from vertical heat flow, and a portion of the lateral flow replacement heat is constantly scavenged by the injection strata on both boundaries. (Figure 13). Since the source of replacement heat is being constantly displaced further from the well bore, the temperature in these zones is often reduced to approximately injection zone temperature.

Upon shut-in, the recovery rate of these strata is retarded by the continuous thiefing of heat over the lateral path to the well bore, and by the lesser formation to well bore differential at a given radius. The equilibrium effects do still exist; however, and all but the very thin zones can be identified. Conversely, a thin injection zone between non-injection strata is affected by the proximity of the two dominant heat sources, and the recovery within the well bore is accelerated.

Qualitative identification of the injection zones can usually be made after a relatively long shut-in period. A single traverse is made and the cool anomalies assumed to be the injection zones. Vertical heat effects tend to average all the temperature parameters, however, and only the top and bottom of the gross injection interval can be determined by this means. These interpretations are subject to error due to the myriad temperature influences on the well bore fluids.

Projecting the initial data through the time of maximum vertical effects allows identification based on lateral heat flow. This establishes a rate of recovery at each depth that is the result of temperature differential at a given radius, formation characteristics, well bore mechanics, injection conditions. These projections provide data that can be used in formulations based on the radial flow concept of heat transfer.

The data derived from extrapolation of lateral recovery rates evolves a relationship that can be used in quantitative calculation of water distribution in the injection well.

Projection of the non-injection zone temperature to the normal gradient leaves the anomalies caused by the water injection zones. These anomalies have a relationship that reflects the distribution of water, but only if additional correction based on zone thickness and bore hole to formation differential is applied. Determination of the actual zone thickness presents a problem, but a method incorporating the angle of slope change and degree of slope progression is being used at present, with good results.

Sufficient corroborating data has not been compiled at this writing to present these calculations, but a progress report to the industry will follow at a later date.

INSTRUMENTATION

The heart of the computerized application is the sensitive digital recording system.

Through use of digital tapes, accurate recording of slight temperature changes is possible. Regular analog recording systems use time

constant circuitry that averages many of these pertinent data, and visual definition becomes impossible.

The major objective of a digital recording system at the well site is to record the information obtained from the sonde in the bore hole with maximum accuracy, eliminating the variables inherent in electronic conversion systems and accuracy limitations of strip chart recorders.

This is accomplished by recording the frequency output of the sonde directly on tape as frequency and making the conversions to temperature in a computer. Additional information, such as vertical and horizontal differentials, can be computed with realistic values at maximum accuracy. The computer output can then be printed in columnar or graphic form for visual interpretation.

The mechanics of the system are shown schematically in Figure 14. The temperature sonde uses a sensitive probe (usually a linear compensated thermistor).

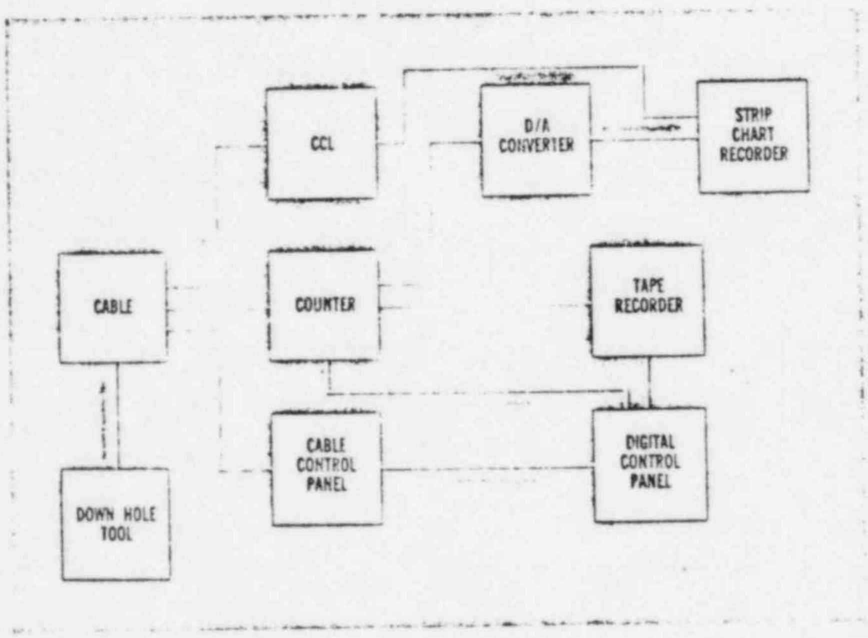


Figure 14. Digital System Schematic

This sensor will vary with resistance depending upon its temperature and is incorporated in an RC circuit which controls a relaxation oscillator. The frequency output is directly proportional to the resistance of the sensor. The downhole signals are fed through the conductor cable to an event counter, coded, and put on magnetic tape in a BCD 1248 code. The BCD output will also go to a digital to analog converter which will drive a strip chart recorder. The function of the strip chart

recorder is to provide a visual record of the temperature runs for reference only. All interpretations will be made from the digital tape through a computer. A minimum of four temperature logging run data is digitally recorded on tape. The first run during injection and runs 2, 3, and 4 at a set interval not to exceed 2 hours between runs with the well shut in. Temperature readings can be recorded 1/2 foot intervals or one foot, two feet, etc. as desired.

COMPUTER PROGRAM

The digital field tape containing runs data is processed through the program tapemake and a Fortran tape is output. This data is in frequency and is converted to temperature. A report on all real runs is generated and through a program the ability is provided to extrapolate new runs to any elapsed time.

Each run real or extrapolated contains temperatures per depth interval, vertical differential at selected depth intervals, and horizontal decay rate from previous runs or to the normal gradient. Computer plots of this information can better define the injection zone as to vertical span and injection volume. All computed variables such as differentials have real values providing improved interpretation information. Typical computer print-outs are shown in Figure 15.

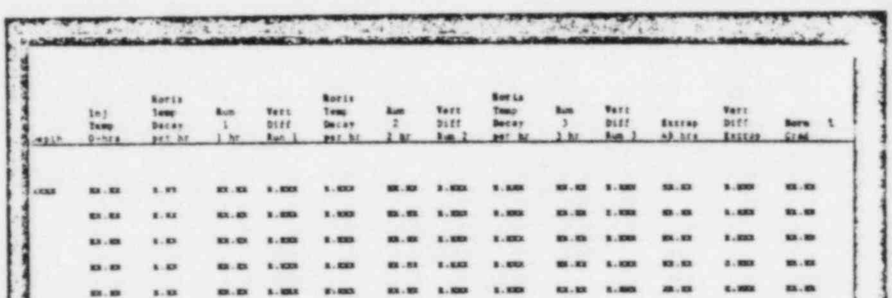


Figure 15. Information from Computer Print-out

The first column is the injection temperatures versus depth. The second column is the horizontal differential or rate of decay vs. depth from the injection run to the first shut-in run. The third column is the first shut-in temperatures versus depth. The fourth column is the horizontal differential between shut-in Run 1 and 2. The fifth column is the vertical differential versus depth for the first shut-in run, and can be selected for any vertical depth interval. Columns 6, 7, 8, 9, 10, and 11 are the shut-in runs at indicated times, decay rate, and vertical differential. Column 12 is the extrapolated run at a selected time based on the decay rate of the previous runs. Any number of extrapolations can be made to observe the data until the indigenous temperature of the undisturbed rock is reached. Column 13 is the normal gradient for the local area. Any set of figures can be printed separately and compared for more detailed interpretation. After column 13, the percentage distribution versus depth is shown. Further information on total volume injected can be obtained by applying the percentage figures to the volume injected.

CONCLUSIONS

The use of digital recording and computer analysis, coupled with logging technique, allows the selection of meaningful temperature data exclusive of the masking effects inherent in regular logging methods. Extrapolation provides a means of projecting this "pure" data to established reference indices, resulting in an accurate injection water distribution pattern from temperature logs.

This concept of temperature log analysis is in its infancy, and the forthcoming months will provide a base of well histories to support the validity of this new service to the industry.

REFERENCE

1. M. Schlumberger, H. G. Doll and M. Perebinossoff. "Temperature Measurements in Oil Wells", 172 meeting Institute of Petroleum Technologists, November 10, 1936.

2. H. Guyod "Temperature Well Logging, Oil Weekly, October 21-28, November 4-11, December 2, 9 & 16, 1946.

3. T. J. Nowack "Estimation of Water Injection Profiles from Temperature Surveys", AIME, October 23-24, 1952.

4. J. M. Bird "Interpretation of Temperature Logs in Water and Gas Injection Wells and Gas Producing Wells", Producers Monthly, August, 1954.

5. Jon T. Moss and Phillip White "How to Calculate Temperature Profiles in a Water Injection Well", Oil & Gas Journal, March, 1959.

6. H. J. Ramey "Well Bore Heat Transmission" 36th Meeting, SPE, October 8-11, 1961.

7. H. M. Bullard, R. D. Clarke, and D. H. Rush "Production Logging as Applied to Post Primary Production" 5th Logging Symposium, May 13-15, 1964.

8. D. R. Peacock "What You Can Learn From Temperature Logs" Petroleum Engineer, September, 1965.

9. B. G. Agnew "Evaluation of Fracture Treatments with Temperature Surveys, SPE, October 3-6, 1965.

10. Aaron Pierce and J. B. Colby "Temperature Surveys - New Uses for an Old Tool", World Oil, June, 1966.

11. Earl Johns "Tracing Fluid Movements With a New Temperature Technique", SPE, March 5-7, 1967.

Reference Notes: All the authors listed were not directly referred to in this text. Their works were studied for any major conflict of theory principle or fact.

ATTACHMENT TO EXHIBIT C

SOCIETY OF PETROLEUM ENGINEERS OF AIME
6200 North Central Expressway
Dallas, Texas 75206

PAPER NUMBER SPE 1752

THIS IS A PREPRINT --- SUBJECT TO CORRECTION

A New Fluid Flow Analysis Technique for Determining Bore Hole Conditions

By

Charles Self and Mat Dillingham, The Western Co., Hobbs, N. M.

ABSTRACT

Measurements of fluid movement in boreholes have been used to determine the porosity and permeability of exposed formations and the efficiency of the mechanical conditions of completions. Until the present time, all analyses using radioactive techniques have been based on calculations dependent upon an accurate knowledge of pipe or hole diameters.

A new technique has been developed, independent of diameters, to provide accurate measurements of fluid flow in casing, behind the casing, and in the open hole. This method measures the radiation intensity of a moving slug of radioactive material in the borehole. As material is lost to the formation, a decrease in intensity is observed providing information for constructing an accurate profile. Calculations are made based on the absorption factor of the rock compared to the borehole fluid and the method of measurement of the intensity of recorded radiation. Case histories are presented demonstrating the accuracy and improvements over other techniques.

INTRODUCTION

Determination of the effectiveness of well completions, stimulation, remedial and secondary recovery techniques provides the engineer with information essential to obtain maximum petroleum reserves from the formations. The most used technique to provide this information has been studies of fluid movement from injected radioactive tracers. The tracer methods have provided general information on channels, thief zone locations, and stimulation effectiveness.

To obtain more detailed information, calculations were made from velocity recordings of the movement of radioactive tracer material in the borehole using hole diameter information at each section of a well. Such information was restricted to sections of wells where accurate caliper information was available. After stimulation, the hole diameters change both in open-hole sections and cased sections, restricting accurate fluid movement analysis to inside casing or undisturbed sections of uncased boreholes.

In wells where abrupt changes in diameter occur due to casing programs or irregular boreholes, the hydraulic flow diameter and calipered diameters vary directly with the degree of change. This is demonstrated by laboratory tests as shown in Fig. 1. In this test, a 2-in. section of tubing was swedged to a 7-in. OD casing section. Readings were taken, at various metered rates of injected fluid, of the time interval recorded for a slug of radioactive

Illustrations at end of paper.

material to travel from A to C, and from B to D. From the recorded times, the fluid movement rates were calculated based on the actual ID of the casing. Comparison of the calculated rates for the two intervals and the metered rates at input shows a wide discrepancy. Normally, velocity readings are made at sufficient distance from diameter changes to provide more accurate information.

A study of recorded tracer intensities obtained from following movement of radioactive material in the borehole has shown detailed information can be obtained behind casing or in irregular boreholes to determine fluid movement into formations.

THEORY

The intensity of radioactivity observed by a detector is determined by the sensitivity of the detector, strength of the radioactive material and the absorption coefficient of well fluids, casing and formations.

The detector sensitivity is matched to the radioactive material strength and remains constant for each survey. The radioactive material is prepared in a solution compatible with the wellbore fluids to provide uniform distribution. The well-casing shielding effects are a known constant that uniformly reduces the recorded intensity of the material.

Of major importance is the shielding or radioactive absorption qualities of the formations. As a percentage of the radioactive material enters a zone in the wellbore, a corresponding decrease in recorded activity is observed; likewise in areas where there is no fluid loss to the formation, the activity is constant. Three fourths of an inch of concrete will reduce the existing radiation level to one-half its original value. For each additional increment of penetration, the level of activity will be decreased at the same rate. By the accurate control of logging speeds through a moving radioactive slug, the penetration into the rock will be an equal distance and the subsequent radiation decrease will be uniform depending on the permeability of the section.

The diameter of the borehole has a negligible effect on the recordings due to the low absorption coefficient of the well fluid and the dispersion of the radioactive material in the fluid.

Uniform logging runs through a moving slug of radioactive material inside or outside the casing will provide a series of recorded intensities that can be measured to provide an accurate profile of fluid movement or loss to the formations. The method of measurement of the recorded intensities is the basis of interpretation of the results.

METHODS OF MEASUREMENTS

Velocity profile tools using downhole tracer ejectors with dual gamma-ray detectors provide information on possible channels or communications. When such information is observed, the amount and extent of the channels are defined by ejecting tracer material and following its movement with a gamma-ray detector. This technique has been commonly used to verify the information obtained from velocity profiles and has been an accepted practice for annulus profiles.

Fig. 2 is from a well where an annulus profile was attempted with the velocity technique. The scattered points on the right are velocity readings calculated from information observed with the profile tool inside the tubing and the ejected radioactive material moving down the tubing into the annulus through a sliding sleeve above the packer, and back up the annulus. Due to the scattering of points, an assumed average profile curve was constructed as shown. On the left are a stack of straight tracer runs following a slug of radioactive material as it moves up the annulus. It can readily be seen that the peaks of intensity of each tracer run present a reasonable profile of fluid loss from the 100 per cent reading at the bottom to the 0 per cent reading at the top.

From the studies of tracer runs a method of measurement has been derived to provide an accurate profile of fluid loss to the formation. For accuracy of information, all tracer runs are recorded at the same logging speed and sensitivity. Each tracer run is logged completely through the radioactive material. Recorder deflections of the tracer runs are set so that the complete amplitude of deflection will be contained on the recording paper.

Fig. 3 shows the method of measurement of the recorder intensities. First, a line is drawn for the average base line of each run. Next, lines are drawn on the top and bottom of the slopes of the intensity peak. These lines are extended to intersect at a point to the right of the intensity peak and the base line as shown. When the radioactive material has traveled a long distance in the wellbore, or as fluid is lost to the formation, the base of the deflection spreads and the intensity peak shortens. Care must be taken to draw the slope lines along the actual radioactive material peak.

Starting with the first recording, after the radioactive material is dispersed in the well fluid, measure from the slope line intersection to the base line and add to this the

measurement along the base line between the intersections of the slope lines with the base line. Record this total measurement for the 100 per cent reading. Repeat the measurements for each of the recorded tracer runs in sequence and when compared to the 100 per cent reading, the amount of activity remaining in the borehole can be obtained. Measurements of only the recorded peak of the moving radioactive material is of major importance. Prolonged activity or secondary peaks are not considered and have no relationship to the construction of a profile. They do provide observations of channels or partial change in fluid movement direction and can be analyzed separately.

CASE HISTORIES

Comparisons in over 500 wells of velocity profiles to tracer profiles have proved the accuracy of the tracer technique. In areas of uniform diameters, the same profile is obtained with both types. The following case histories are from the log files of injection well profiles.

Fig. 4 shows the comparison of profiles obtained using a packer spinner tool [Vel-Pak], velocity survey, and the tracer method. The Vel-Pak survey only measures fluid flow inside the casing and readings are restricted to unperforated sections. The information obtained determines only how much fluid left the casing at each set of perforations. The velocity profile presents more information on fluid loss through the perforated intervals but is subject to error from the effect of long perforated intervals on the diameter. In these areas, fluid is moving both inside the casing and outside the perforations. An accurate hydraulic diameter is unobtainable. The tracer profile is measuring the intensity of a moving radioactive mass and is unaffected by perforated zones or casing. The resulting profile shows where the fluid is entering the formation.

Fig. 5 presents the actual tracer runs with the measurement technique on the right side and the accurate profile on the left. From this profile, channeling can be seen between the perforated intervals.

Fig. 6 is an example of a well condition with the tubing set partially through the open-hole section. The velocity profile is consistent in the section below the tubing. In the annulus behind the tubing, based on gauged hole diameters, the readings are erratic. A tracer profile confirmed the lower velocity readings and provided an accurate profile of the fluid movement up outside the tubing.

Fig. 7 shows the recorded tracer runs for the section behind the tubing of Fig. 6. The first tracer run at the bottom shows a split in the fluid movement by the double peak on the recording. The successive runs as the fluid moves up are shown on the right and the profile obtained is shown on the left border.

Fig. 8 is a comparison of a velocity profile and a tracer profile with different results. The velocity profile shows greater losses than the tracer profile. The differences are due to the measurement techniques. The velocity profile is measuring fluid movement inside the casing, and the tracer survey records intensities both inside and outside the casing, resulting in higher readings. The increased quantities of the tracer run indicate channeling from the perforations from 2,016 ft to 2,027 ft down to 2,138 ft, with no fluid movement inside the pipe below 2,092 ft; losses to the formations are indicated by the solid bar graph on the left side of the chart. In addition to the channeling down, fluid is also traveling up to 1,982 ft as indicated by the profile above the perforations.

Fig. 9 shows the tracer runs for the profile of Fig. 8.

Fig. 10 shows the erratic readings obtained in an open-hole section with radical diameter changes. The dashed line is the caliper of the open-hole section. At areas of extreme hole changes, the velocity profile readings are invalid due to the differences of hydraulic diameter of the fluid flow and the calipered diameter. The tracer technique provides uniform readings throughout the entire section.

Fig. 11 is a comparison of techniques before and after the mechanical conditions of a well were changed. The first velocity profile was obtained before a liner was set and cemented. A second velocity profile was run approximately one year later after the liner had been set and perforated, showing a change in fluid movement due to the liner placement. Also a tracer profile was obtained after the liner placement, showing the fluid movement outside the liner. Due to the similarity of the original velocity survey and the last tracer survey, the placement of the liner had very little effect on the fluid into the formation.

Fig. 12 illustrates a technique of tracer-logging fluid movement up and down simultaneously. The first tracer run at the bottom of the tubing shows a split in intensity. The following runs show the movement of the intensity peak up and the intensity peak down. In well conditions with long sections, individual tracer runs for each direction of flow would be made to increase the number of runs and provide better detail.

Fig. 13 is the resulting profile of the runs in Fig. 12 and the velocity profile below

the tubing. In the area from the tubing bottom to the total depth, the velocity profiles and tracer profiles are the same. The tracer profile also shows the fluid movement up and behind the tubing.

Fig. 14 is a comparison of a velocity profile with the tubing bottom above the zone of interest. The tubing was then lowered to below the zone of interest and profiles obtained 25 months later. A comparison of the profiles shows very little change in fluid movement into the formation with the change in tubing placement.

Fig. 15 illustrates both an additional usage of the tracer technique to present more detailed analysis of the temperature survey and further substantiation by the temperature survey. The solid line profile in the center section is a regular velocity profile. The tracer profile, the dashed line, shows evidence of channeling from 4,356 ft to 4,428 ft with fluid entry into the formation from 4,380 ft to 4,430 ft. The detailed temperature survey on the right shows the formation cooling over this interval as well as cooling from the channeling from 4,350 ft to 4,380 ft.

Fig. 16 is a comparison of temperature runs vs time on the right and a tracer profile on the left. The tracer profile verifies the shifts at 4,640 ft and 4,940 ft to be due to changes in hole diameter only. Fluid entry into the formation is shown by the bar graphs at the left over the interval of cooling shown by the temperature survey.

SUMMARY AND CONCLUSIONS

The recording of intensities of moving radioactive material in a borehole has been used for qualitative measurements for over 20 years. The theory has been proved in all types of commercial application. The measurement technique of the intensities as shown by the examples in this paper can be a reliable method for obtaining quantitative analysis of fluid movement, both inside and outside casing.

The tracer drag run technique provides a method of substantiating other survey information and allows a point by point analysis of fluid distribution. The limitations of other techniques such as irregular hole sizes, changes in flow rates, and problems of interpretations are eliminated with the tracer technique.

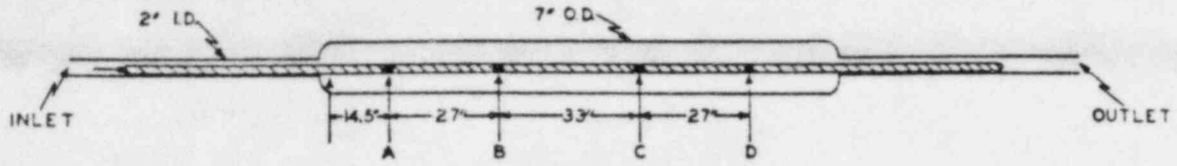
To better differentiate this method from other tracer-type surveys and give recognition to the developer, the tracer profiles discussed here have been called the "Self Method of Fluid Movement Analysis".

REFERENCES

1. Cocanower, R. D. and Morris, Billy P.: "Selection of Profile Techniques Based on Well Conditions", J. Pet. Tech. (May, 1966) 576-588.

2. Johnson, Wallace and Morris, Billy P.: "Review of Tracer Surveys", paper presented at Southwestern District, Div. of Prod., API (March 18-20, 1964).

3. Alberts, A. A. and Cocanower, R. D.: "Application of Radioisotopes to Subsurface Surveys", paper 398-G presented at AIME Annual Meeting, San Antonio, Tex. (Oct., 1954).



CORRECTED METER RATE B.P.D.	UNIT TIMES A-C	UNIT TIMES B-D	CALCULATED RATE A-C	CALCULATED RATE B-D
48 1/2	96	136	164	115
97	40	44	394	358
194	34	34	463	463
388	16	23	983	684
548	12	14	1310	1124
776	7	10	2245	1570
857	8	9	1965	1750

Fig. 1 - Laboratory Comparison of Calculated Flow Rates to Actual Rates in Areas of Different Diameters

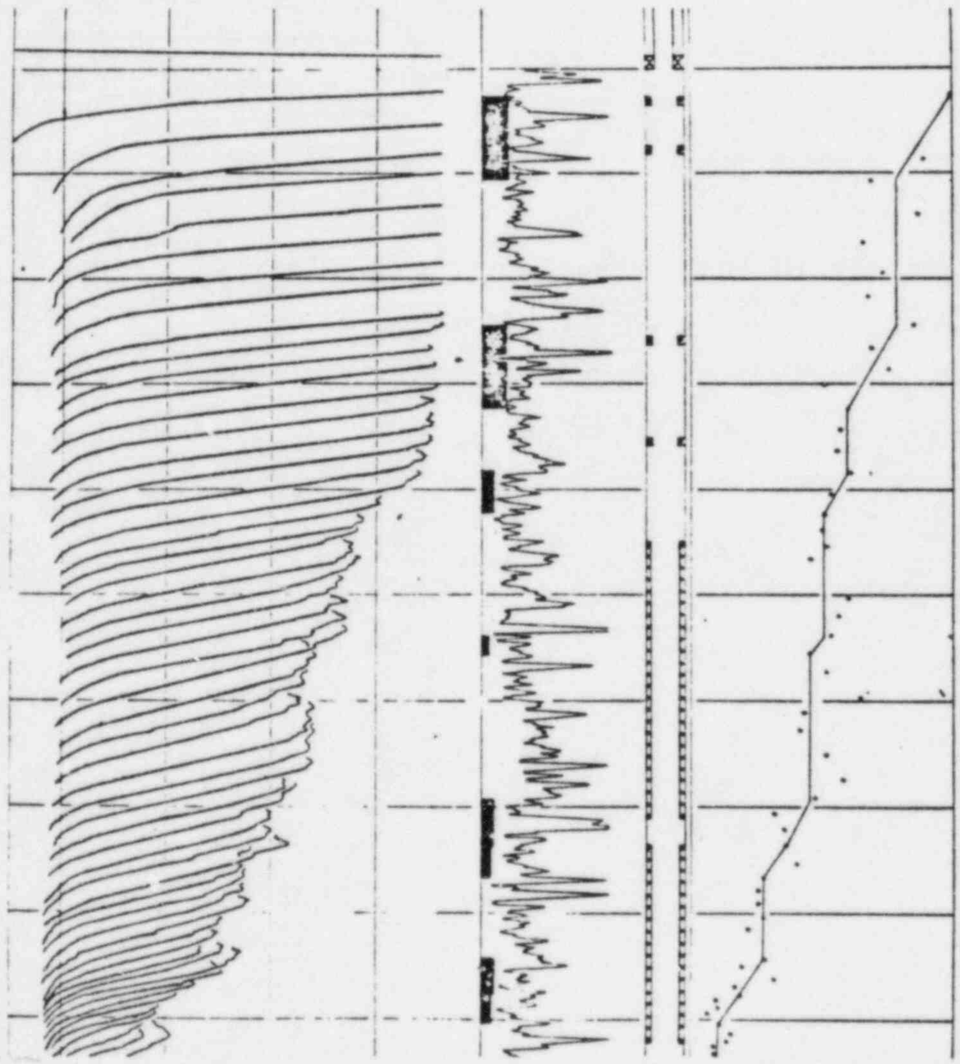


Fig. 2 - Annulus Profile Comparison of Velocity Technique and Tracer Run Stack

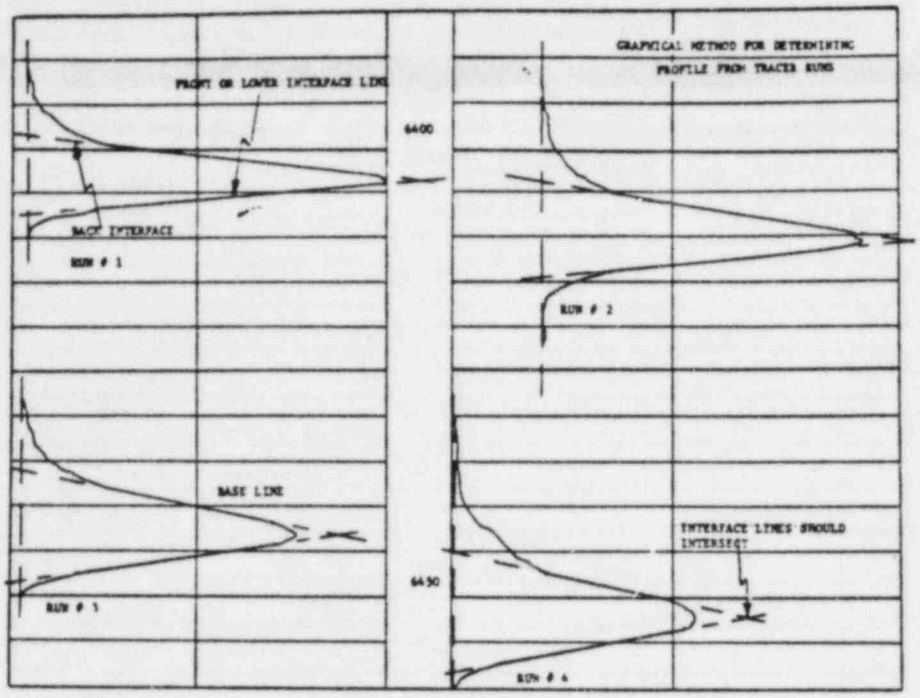


Fig. 3 - Tracer Run Intensity Measurement Method

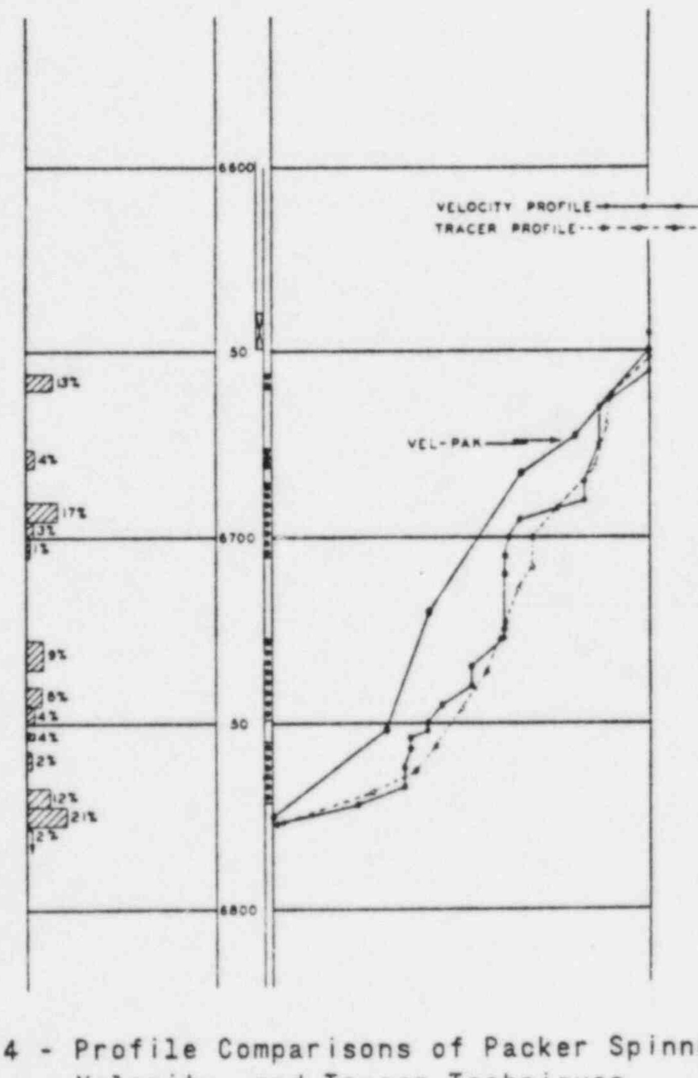


Fig. 4 - Profile Comparisons of Packer Spinner,
Velocity, and Tracer Techniques

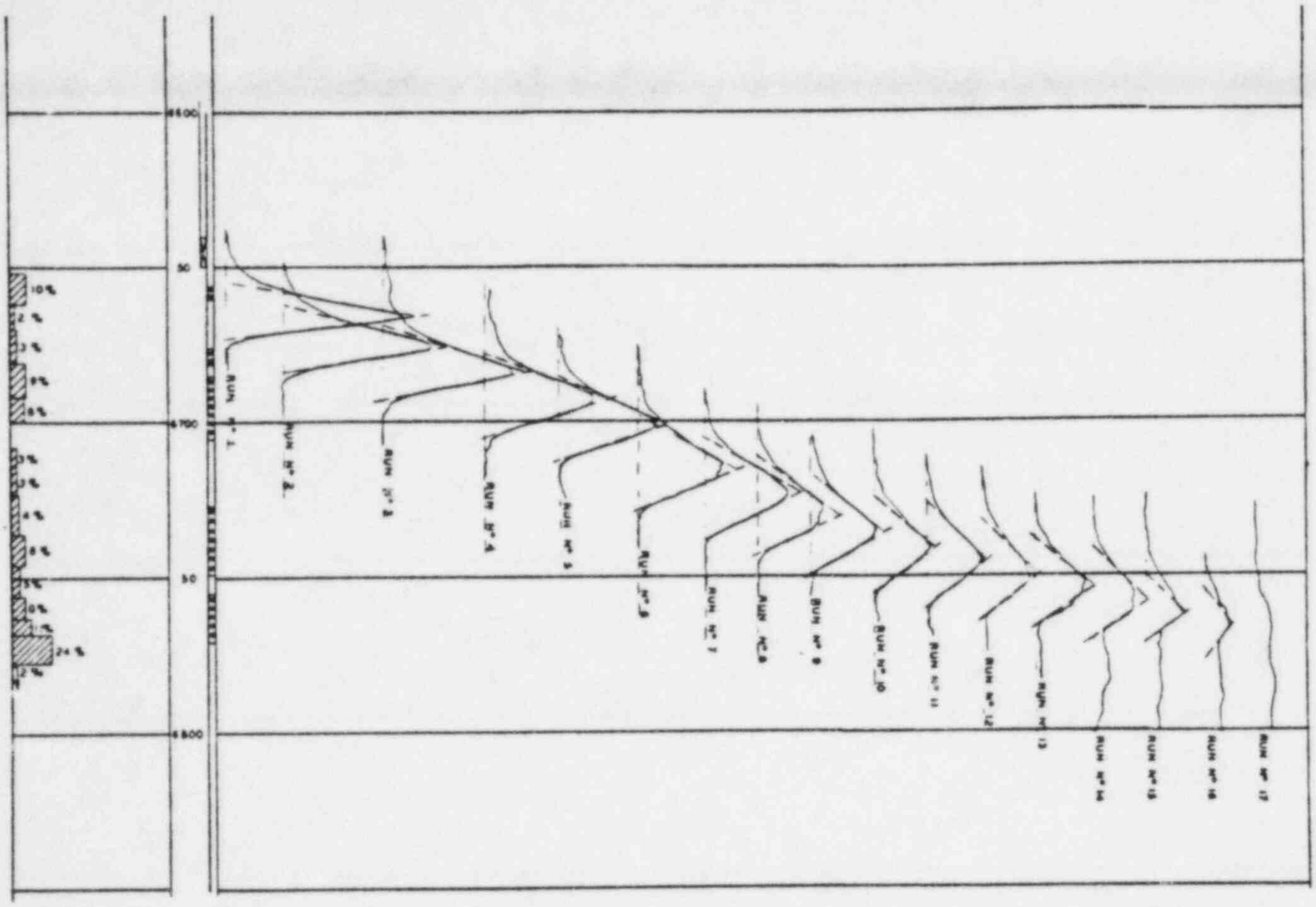


Fig. 5 - Tracer Intensity Runs Showing Measurements

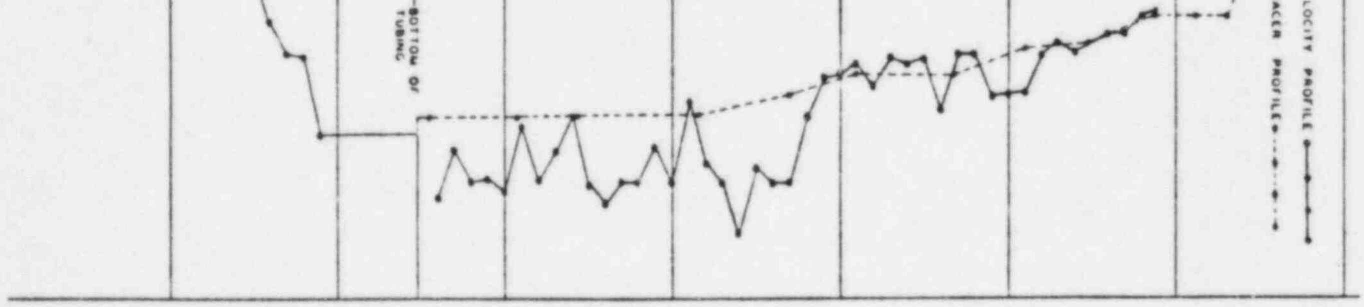


Fig. 6 - Profile Comparisons in Uncased Section Below Tubing and Outside Tubing

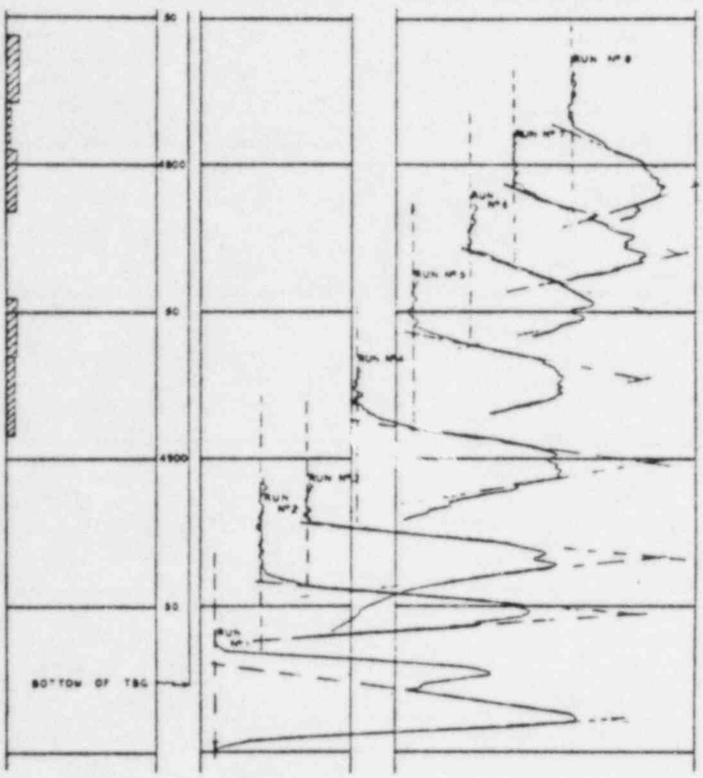


Fig. 7 - Recorded Tracer Runs for Figure 6

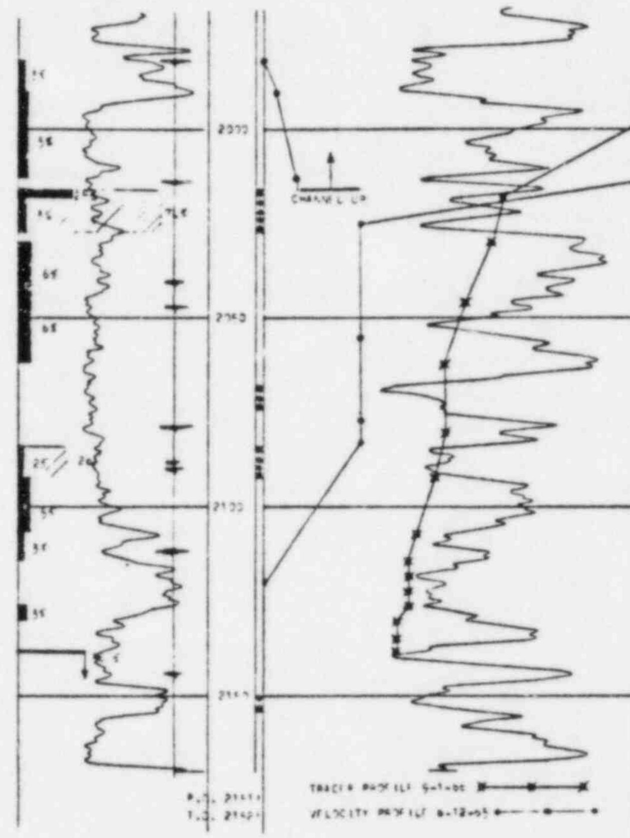


Fig. 8 - Comparisons of Velocity Profile and Tracer Profile Indicating Channelling

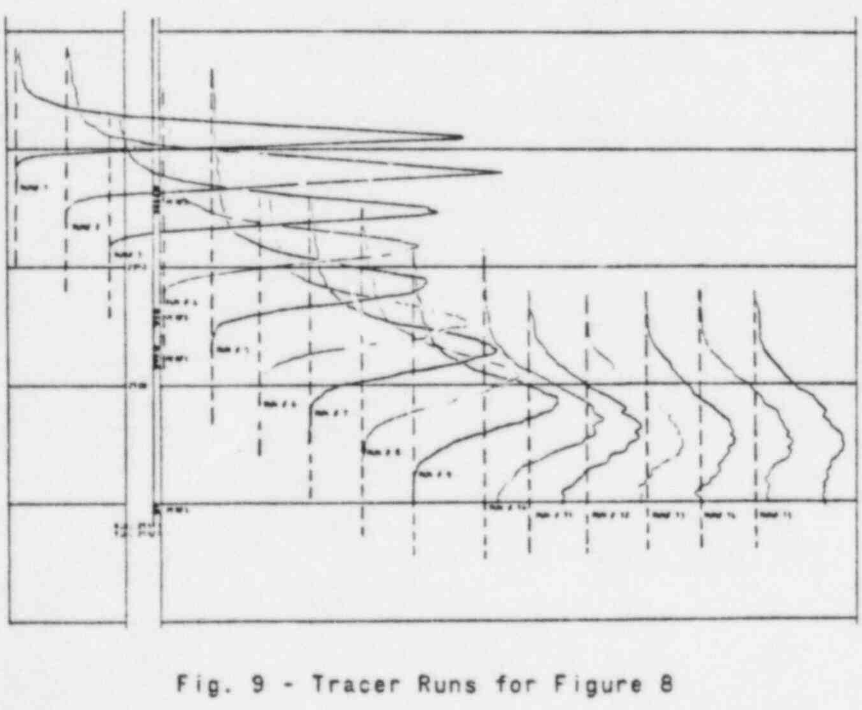


Fig. 9 - Tracer Runs for Figure 8

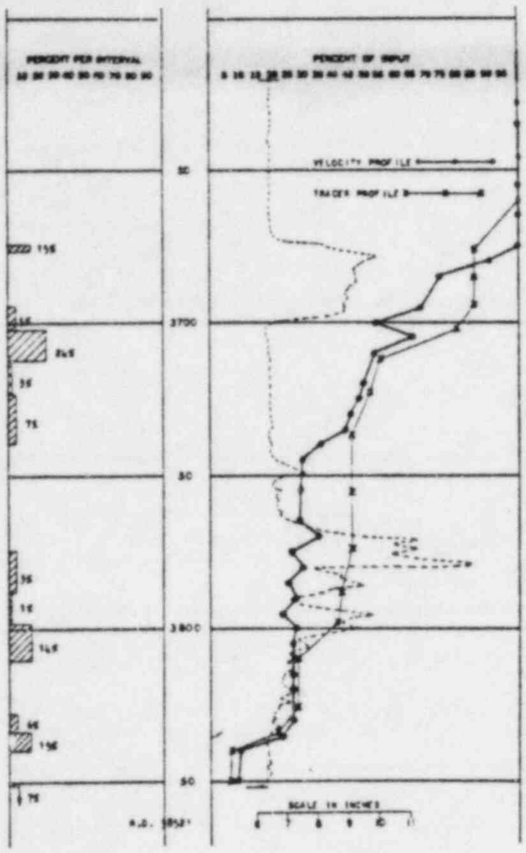


Fig. 10 - Comparisons of Velocity and Tracer Profiles in Irregular Bore Holes

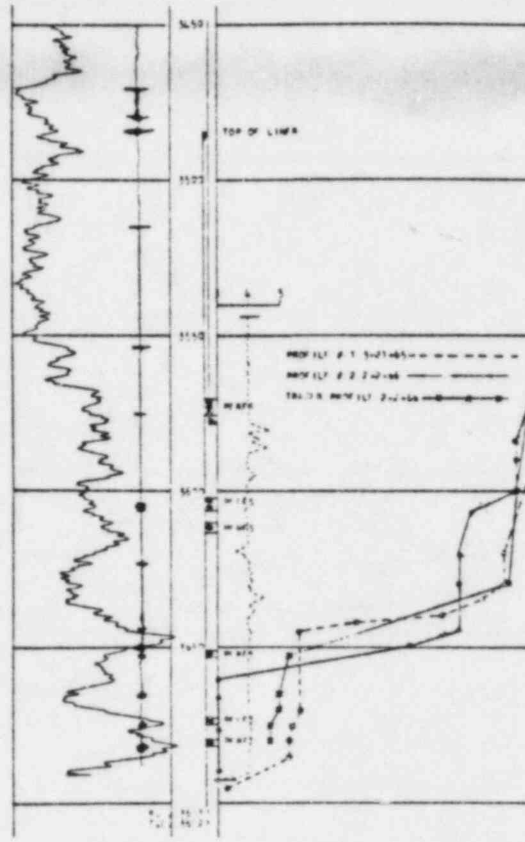


Fig. 11 - Profiles Before and After Liner Placement

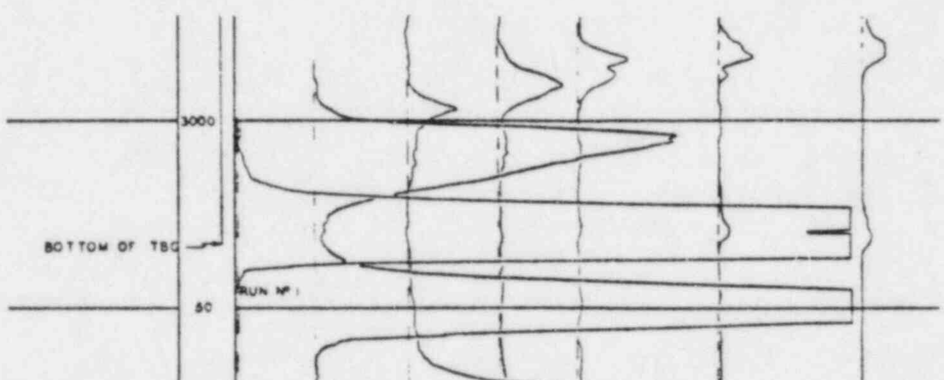


Fig. 12 - Profiling Fluid Movement in Two Directions

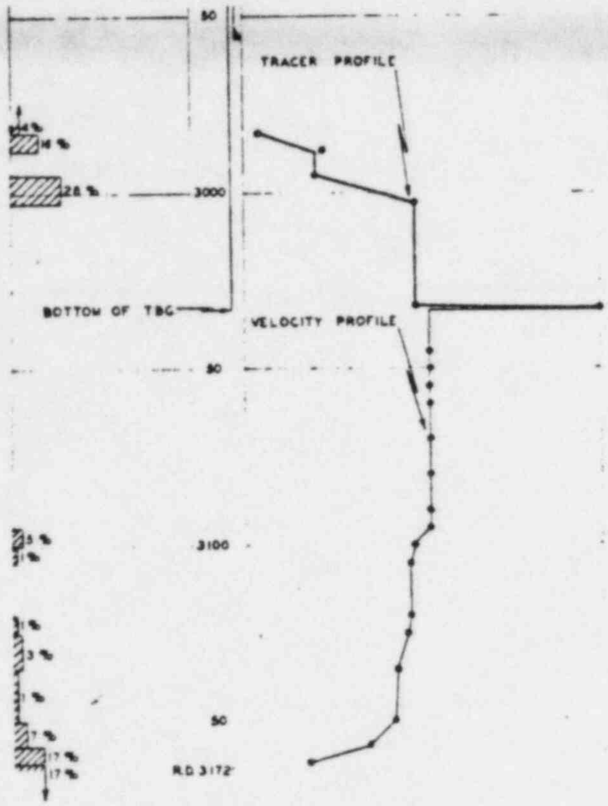


Fig. 13 - Resulting Profile from Figure 12

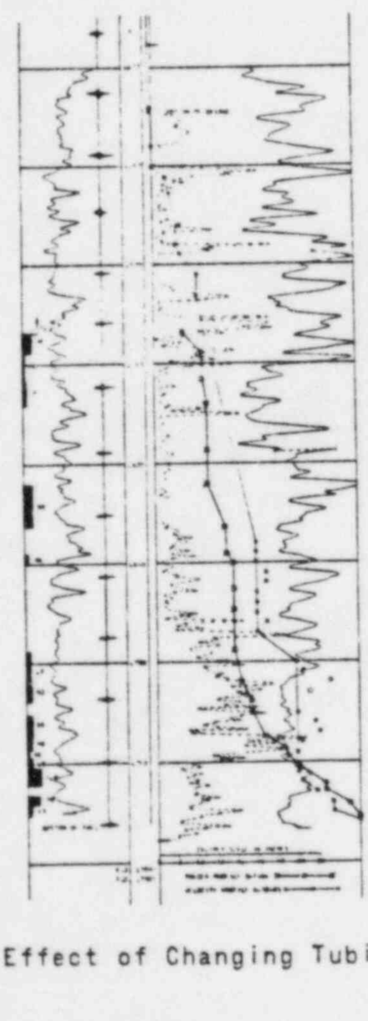


Fig. 14 - Effect of Changing Tubing Position

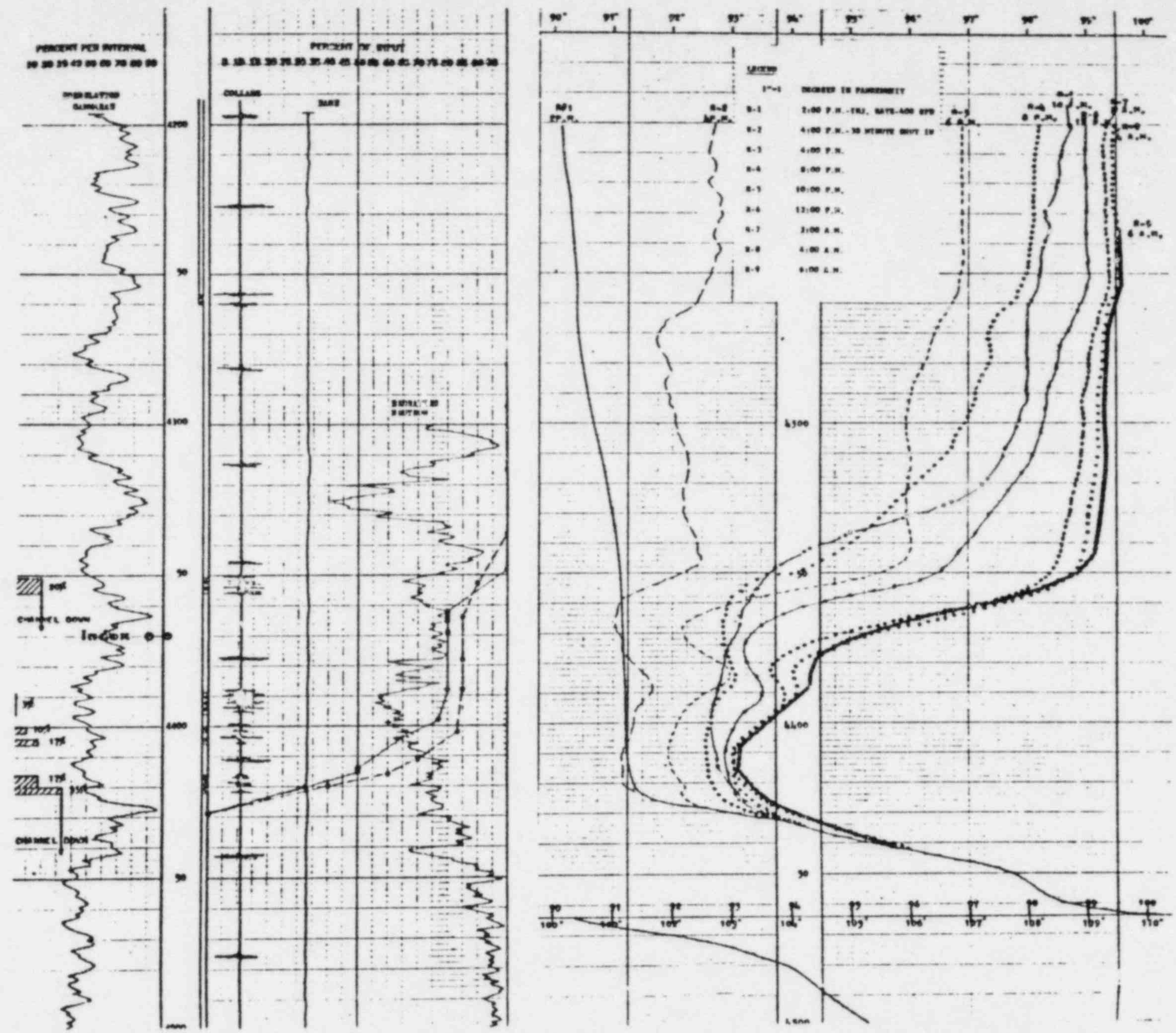


Fig. 15 - Comparison of Tracer Profile and Temperature Survey

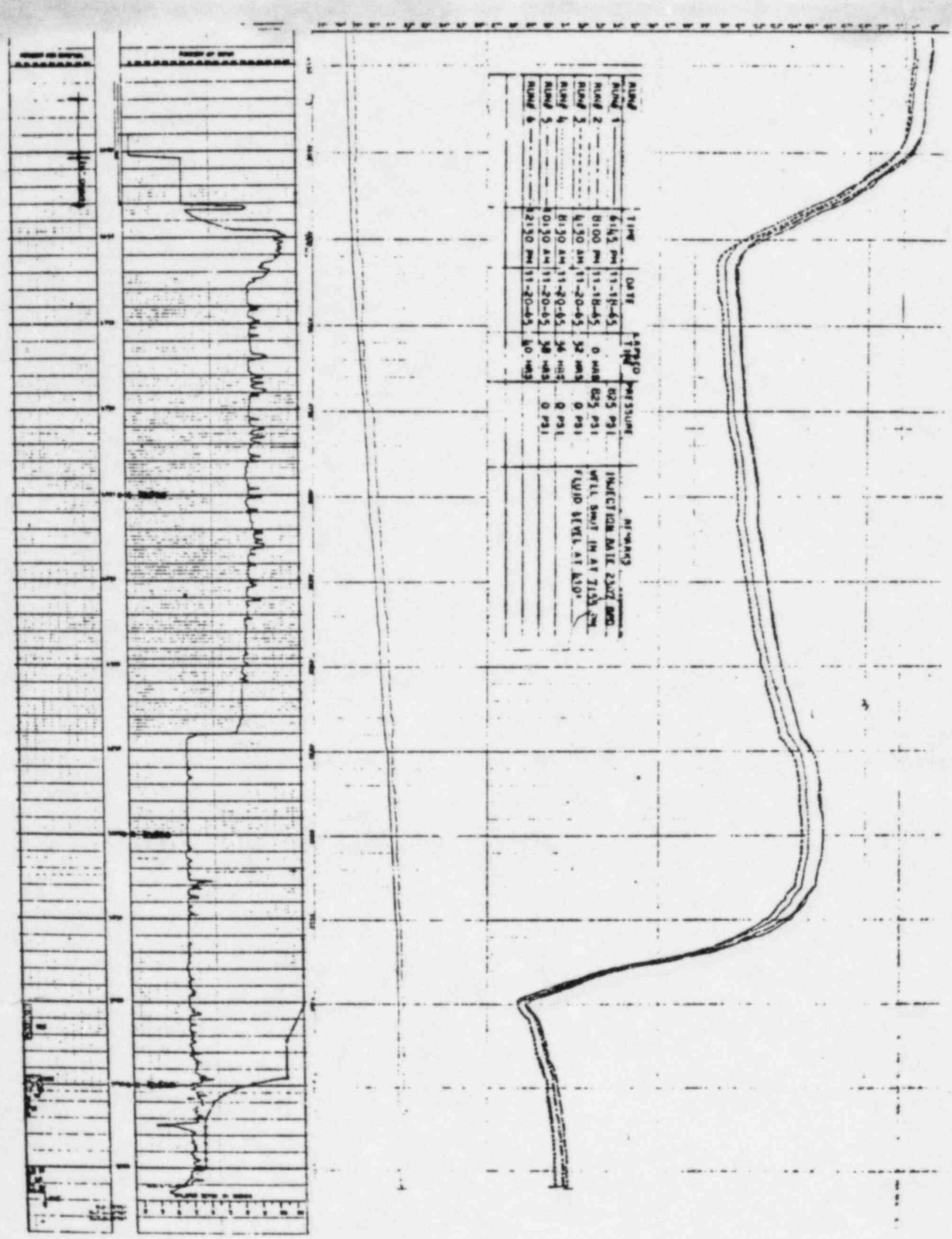


Fig. 16 - Interpretation of Temperature Survey with Tracer Runs

SOCIETY OF PETROLEUM ENGINEERS OF AIME
6200 North Central Expressway
Dallas, Texas 75206

PAPER NUMBER SPE-2255

THIS IS A PREPRINT --- SUBJECT TO CORRECTION

COMPUTERIZED TEMPERATURE DECAY-AN ASSET TO TEMPERATURE LOGGING

By

R. D. Cocanower, Member A.I.M.E., The Western Company, Fort Worth, Texas
Billy P. Morris, Member A.I.M.E., The Western Company, Midland, Texas
Mat Dillingham, Member A.I.M.E., The Western Company, Hobbs, New Mexico

This paper was prepared for the 42nd Annual Fall Meeting of the Society of Petroleum Engineers of AIME, to be held in Houston, Texas, October 1-4, 1968. Permission to copy is restricted to an abstract of not more than 300 words. Illustrations may not be copied. Publication elsewhere after publication in the JOURNAL OF PETROLEUM TECHNOLOGY or the SOCIETY OF PETROLEUM ENGINEERS JOURNAL is usually granted upon request of the appropriate journal provided agreement to give proper credit is made.

Discussion of this paper is invited. Three copies of any discussion should be sent to the Society of Petroleum Engineers office. Such discussion may be presented at the above meeting and, with the paper, may be considered for publication in one of the two SPE magazines.

ABSTRACT

Considerable work has been done on the mathematical interpretation of the information obtained from temperature logs. Detail interpretation has been hampered by bore-hole effects, unstable well conditions, and the time required to obtain valid information. The problems are prevalent in injection profiles.

The technique discussed in this paper provides a means of obtaining accurate injection strata definition and minimizing the well condition influence. A digital tape recording system is described with a computer program to determine the temperature decay rate versus time and horizontal and vertical differentials for any interval. With this information, an extrapolation is projected at a time determined by each field condition. Mathematical data is presented to provide the basis for the computer program and extrapolation. Comparisons of calculated data and analog recordings of temperature runs demonstrate the feasibility of the technique.

Field examples are presented comparing the various temperature logging techniques with the computerized logs to further demonstrate the validity of the information obtained. With the use of computerized temperature logs, fluid distribution can be calculated and presented with a minimum time at the well site.

INTRODUCTION

There has been renewed interest in the usage of temperature surveys for fluid movement analysis in both producing and injection wells. Many techniques have been tried and the results publicized. The major problem in defining accurately the injection zone vertical dimensions was inherent with all the analog techniques. Additional problems of the effect of bore-hole mechanical conditions and the statistical errors common to analog recordings made interpretation more diffioult. Numerous methods have been presented for better definition of injection zones through mathematical calculations of comparisons of shut-in temperature surveys to injection temperature surveys or to the normal gradient. The calculations for each depth interval were time-consuming and still contained the errors common to analog recordings. The digitizing of the signals from the temperature element at the well site and the use of computers for conversions to temperatures, log print-out, and computer projections of this information to a selected time interval provides more accurate definition of injection zones.

CONDITIONS

Fluid movement into a formation strata cools the zone invaded as well as strata above and below the invasion zone. (Fig. 1). The extent of the cooling, both horizontal and vertical, increases with continued injection until steady state heat flow is approached. When the well is shut in for survey purposes, the normal formation temperature continues the transfer of heat to the well bore.

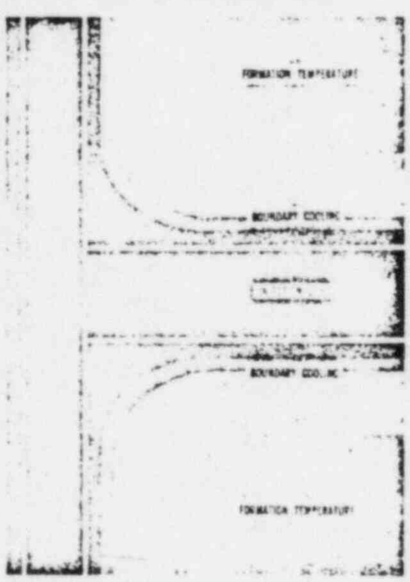


Fig. 1 - Injection Cooling Pattern

The rate of return of the well bore to normal temperature is dependent on the mechanical conditions of the bore-hole and the degree of cooling effected in the strata.

Temperature surveys performed after shut-in show the effect of packers, hole size changes, and cooling of areas (Fig. 2) vertically adjacent to the injection zone. Repeated surveys show a decreasing effect of the mechanical conditions and provide more information on the injection zone.

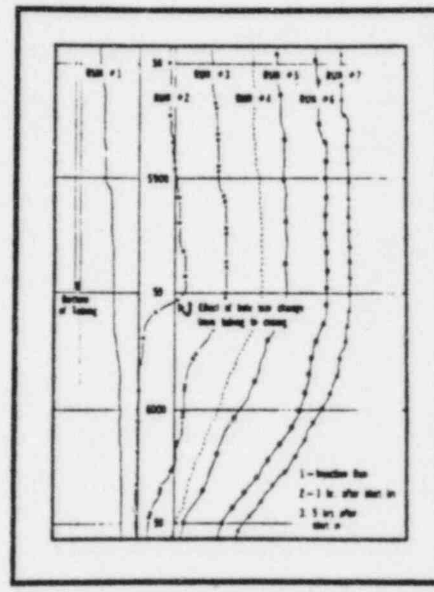


Fig. 2 - Effects of Well-Bore Condition

An attempt to make a single run temperature survey after shut-in can be very misleading. Multiple runs are necessary to distinguish the mechanical conditions from the injection zones.

Repeated runs to define the upper and lower limites of an injection zone are at first affected by the cooling of strata adjacent to the zone, and later by the vertical heat transfer to the injection zone near the well bore. In the first case, the zone may appear too broad, and in the second, the zone could be eliminated from view.

Down-hole sensors with extreme sensitivity are not necessary to gather valid data, but they must have linear reaction over the range of temperature investigation. There has been considerable confusion over the term sensitivity with the development of the surface differential systems. These systems are capable of expanding a down-hole signal to a high degree, but the sensitivity of the system is only that of the sensor in the bore-hole. Too high a sensor sensitivity will make the variance of formation rock characteristics more predominate and lithology

corrections must be made for interpretation.

The surface recording systems must record the signals as received from the temperature sonde to eliminate the errors introduced by the conversion circuits in standard analog recording systems.

The use of a digital tape recording system for recording raw signals from the sonde and converting these signals to temperature through a computer has proved more accurate than analog recording. Apparent shifts in analog recorded logs have been found to be caused by circuitry variations and not bore-hole conditions. (Fig. 3) The time lag between down-hole signals and strip chart recordings is eliminated providing more accurate signal depth information. Further processing of the digital taped information through the projecting formulas provide maximum information at a minimum time.

Analog recordings of the information from the sonde are used for monitoring and display purposes. Figure 4 shows typical surface instrumentation with the analog system and the digital system.

HISTORY

The first fluid flow analysis using temperature decay survey with respect to time were time-consuming, and the information obtained at extended shut-in times was distorted by the vertical heat flow.

Measured horizontal movement of decay runs after shut-in for a period of 3 to 4 hours obtains an average differential between runs and provides a method of extrapolating to a selected time interval reducing the vertical effect.

An improvement on the measured differential between runs was made using the radial heat flow equation:

$$(T_s - T_g) = (T_{inj} - T_g)\, e^{-cdt} \quad \ldots\ldots\ldots (1)$$

SYMBOLS

T_s - the temperature at a depth for some time interval after shut-in.

T_g - the normal gradient temperature at that depth

T_{inj} - the injection temperature at that depth.

dt - the time interval between T_s and T_{inj}.

c - is a constant.

First, the equation is solved for c from the measured temperatures at a vertical interval in the well. The c values are then calculated for 2 or more measured temperatures at the same interval for different shut-in periods. Normally one-half hour, one hour, and two hours shut-in intervals are used.

The c values obtained are then averaged and the average value substituted back in the equation to solve for T (shut-in) at some selected time interval, such as 24, 48 or more hours. This method has produced good injection zone definition.

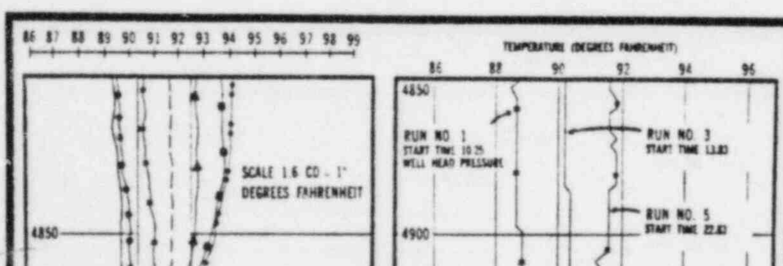


Fig. 3 - Analog and Digital Recordings

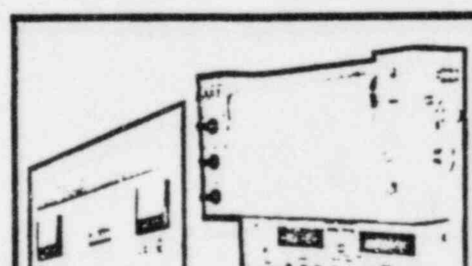


Fig. 4 - Surface Recording Systems

Percentages of fluid injection can be calculated by comparisons of the differential between the extrapolated T and T normal for each interval taking fluid.

The application of the above equation is confirmed in the following mathematical development and theoretical examples, after the mathematical model suggested by Dr. Paul Crawford.

MATHEMATICAL DEVELOPMENT

This section is a summary of the equations showing the mathematical development of the transient temperature fields resulting from the injection of water into oil sands, and subsequent temperatures anticipated when logging these zones. For many waterfloods, the normal geothermal temperature of the oil sand is warmer than that of the injection water at the sandface during injection. For this reason, the development is given in these terms; however, if the injection water was warmer than the oil sand, the same equations may still be used.

When water is being injected at normal flooding rates down casing or tubing, there is only a small change in temperature in logging a distance of 100 feet. This fact has been theoretically forecast and found true in practice. For example, the water temperature may increase 0.8°F in logging a 100 foot interval at depths of near 4000 feet. At the face of the oil sand or zone taking water, there appears to be little or no change in water temperature from the top to the bottom of the pay. If the water temperature should be 80°F at the center of the pay, it will most likely be 80.0 ± 0.4°F for thirty to forty feet above and below the injection interval during the period of injection. Recognition and field verification of this permits one to formulate the equation for the desired temperature fields.

In analyzing this problem, one may assume for engineering purposes, that there is a constant temperature difference between the water flowing in the hole slightly above, into, and slightly below the pay, and the normal geothermal temperature of the strata. This temperature difference between the water and the sand may be on the order of 20°F, but will depend on many things including the time of year, well system, and previous operating conditions. This temperature difference between the water and geothermal temperature is accorded the symbol ΔT.

The temperature change Δt in the rock at a distance z above or below an injection interval, out a radius of r from the well at time Θ, is given by:

$$\Delta t_{z,r,\theta} = (B_{z,r,\theta})\,(A_{r,\theta})\,(\Delta T) \quad \ldots\ldots(2)$$

where:

$$B = \operatorname{erf}\left\{\frac{z}{2\sqrt{a(\theta-\theta r)}}\right\} \quad \ldots\ldots(3)$$

$\Theta,_r$ is that time in hours satisfied by

$$0.0 = \pi r^2 - \left[\frac{qC\ h\ a\ \ 350}{96\ K^2}\right] \times$$

$$\left[e^{b^2}\ (1-\operatorname{erf}b) + \frac{2b}{\sqrt{\pi}} - 1.0\right] \quad \ldots\ldots(4)$$

See Note (a).

$$b = \left[\frac{2k}{Ch\sqrt{a}}\right]\ (\theta,r)^{\frac{1}{2}} \quad \ldots\ldots(5)$$

$$A_{r,\theta} = -\frac{2}{\sqrt{\pi}}\int_0^{\infty} e^{-\frac{k\ \mu^2\theta}{p\ e}} \times$$

$$\frac{J_o(ur)Y_o(ua) - Y_o(ur)J_o(ua)\ du}{J_o^2(au) + Y_o^2(au)} \quad \ldots(6)$$

See Note (b).

Note (a). This equation was originally derived by R. D. Carter for application to fracturing, but has application here. See Howard and Fast, API Drilling and Production Practice 1957; Marx and Langenheim AIME Trans., Vol. 216 (1959).

Note (b). A rather extensive literature is available on the evaluation of this integral. See Proc. Roy. Society Edin. A, 61 (1942) 229; Perry and Berggren, Univ. of Calif. Publication in Engineering 5 (1944) 59; Jaeger, J., Math. Phys., 34 (1956) 316; Goldenberg, Prod. Phys. Soc., B, 69 (1956) 256.

SYMBOLS

a	=	thermal diffusivity of rock
Θ	=	total injection time, hours
Θ,r	=	time required for cool water to reach a radius r, hours
z	=	vertical distance above or below injection zone, feet
ΔT	=	geothermal temperature minus water temperature -°F
Δt	=	temperature change in rock, °F
q	=	water injection rate into pay thickness h, bbls/day
h	=	injection zone thickness, feet
k	=	thermal conductivity of rock
p	=	density of rock, lbs/ft^3
c	=	specific heat of overburden rock, Btu's/lb°F
C	=	thermal heat capacity of rock taking water Btu/cu. ft.°F

$$\mathrm{erf}(x) = \frac{2}{\sqrt{\pi}} \int_0^x e^{-g^2}\, dg$$

The above equations may be used to forecast the temperature in the rock during water injection. During shut-in, there is a temperature rise along the sandface, and this rate of rise differs because the temperature field of the zones taking water differs greatly from the zones not taking water.

During shut-in, the temperature rise in the well bore may be calculated by relaxation techniques using equations of the following type reduced to cylindrical coordinates:

$$\frac{J^2T}{Jx^2} + \frac{J^2T}{Jy^2} + \frac{J^2T}{Jz^2} = \frac{1}{\propto}\ \frac{JT}{J} \quad . . . . . (7)$$

The coefficient $\propto$ is slightly different for the pay zone and the over or under-burden.

The net result of the very significant difference in the temperature distribution in the pay and impermeable zones is such that a large difference occurs in the rate of temperature recovery at the well bore. If the actual temperature rise at the well bore is recorded at the end of one-half, one, two or more hours, the rate of the temperature rise during this short interval may be used to forecast or project the temperature at a later period, such as 24, 40 or 100 hours. This is accomplished by use of equation (1).

Constant "c" is used to project the temperature at a later time, i.e. 24, 40 or 100 hours. These projected values of temperature provide an excellent basis for selecting the zones taking water. This is illustrated in the following section.

THEORETICAL EXAMPLE

The calculation of this theoretical example assumed that water was injected into eight feet of oil sand at a depth of 4006 to 4014 feet. See Fig. 5. The normal geothermal temperature at this depth was 100°F. The water temperature reached the sandface at 90°F and was injected at a high rate for a period of about one week, after which the well was shut in and the temperature profile recorded after one-half, one, and two hours. There was assumed to be no flow of heat or mixing of fluids in the well bore.

Figure 5 shows the temperature rise six feet above or below the pay ranged from about two to three degrees F for a one-half to two hour shut-in respectively. After 30 minutes, it will be seen that there was only a very slight warming of the pay. After two hours, the heat had penetrated a greater depth as shown.

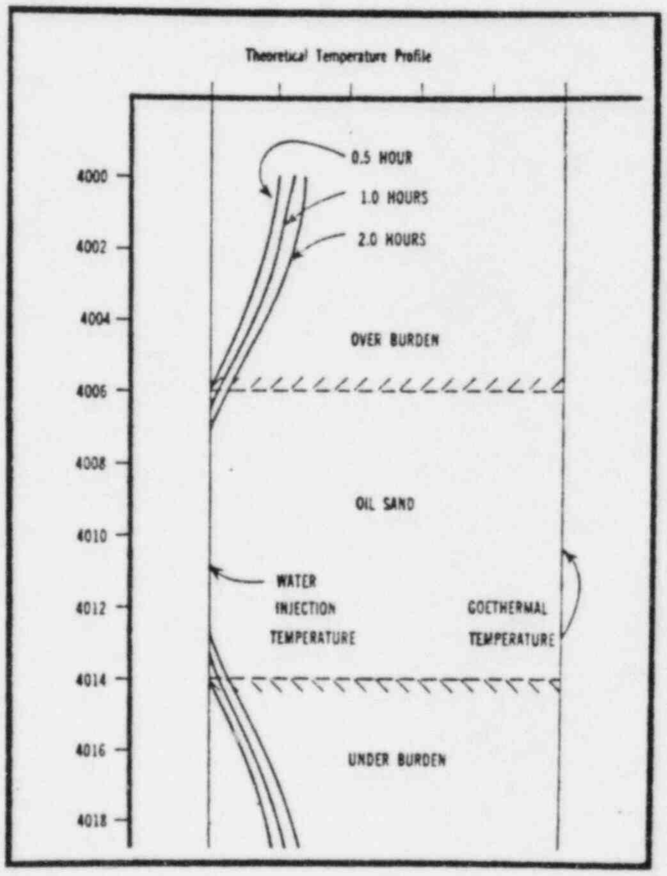


Fig. 5 - Calculated Temperature Profile

Utilizing the thirty minute temperature profile shown in Fig. 5 and equation (1), 48 hour projections were made of the temperature. This projection is shown in Figure 6. The 48 hour projection indicates an almost 100% temperature recovery in both the over-burden and under-burden. A temperature transition zone exists at the interface between the oil sand and the conditions assumed here. This technique provides a very sharp method of selecting the intervals accepting the injection water.

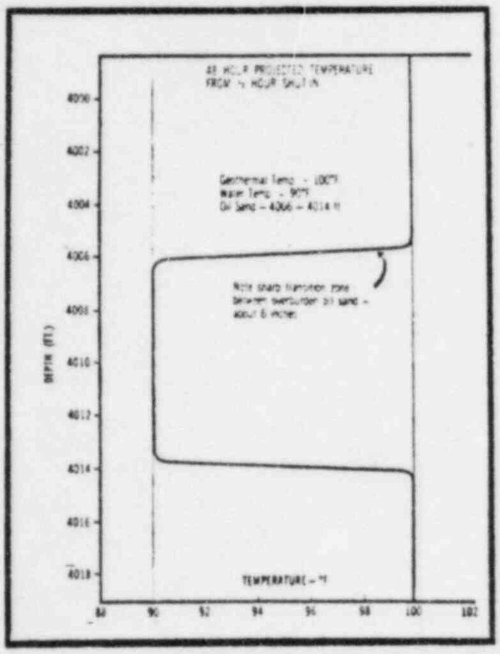


Figure 6

PRACTICAL APPLICATIONS

The development of these calculations is predicated upon absolute, unaffected temperature data at all depths. The methods of data gathering and the physical data collection points do not lend themselves to this concise information in actual practice. Therefore, the ideal determination of injection zones is modified by some degree by the spurious heating effects observed at each collection point.

Identification of the actual zones of injection depends upon comparison of the residual ΔT of the zone when the temperature in all non-injection strata has recovered to ambient temperature. The long term investigation necessary to observe this recovery is time-consuming and is subject to maximum effect from vertical heat flow. These vertical effects destroy the true proportional recovery within the bore-hole and render the information invalid for calculations.

The technique of digital recording of the initial transient recovery rate, and extrapolation of these data through the period of vertical heat flow effects develops sufficient valid data for computation. The extrapolated temperature curves then approach the ideal projections to the degree that accurate determination of zone extent and residual cooling can be made. This information can be realted to the proportionate distribution of injection fluids.

The distortion of the recovery rate and vertical diffusion of temperatures observed in extended time investigation is exemplified by Fig. 7 and Fig. 8, analog plots of digital data.

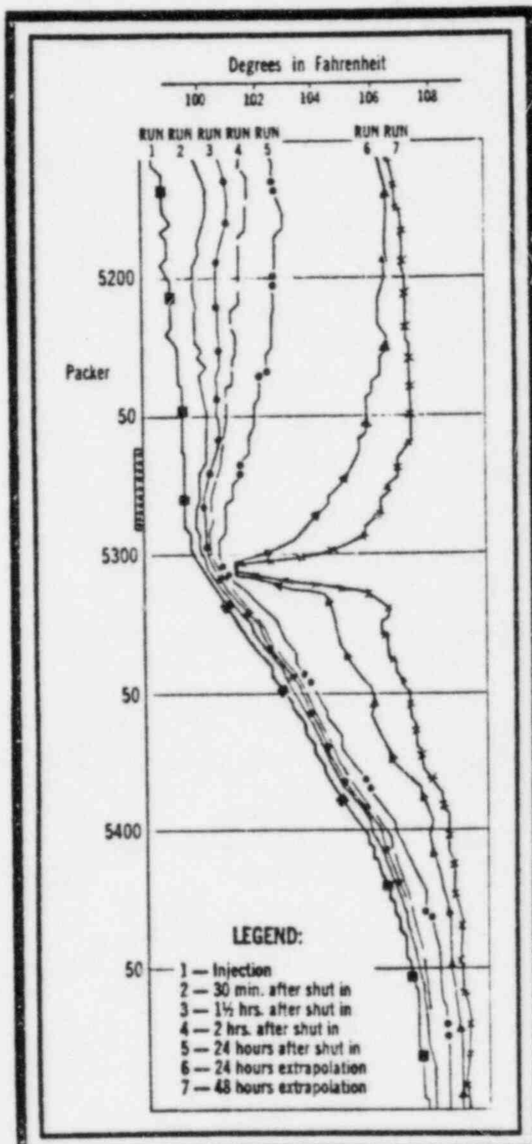


Fig. 7

Digital Plots

Figure 7 is a gas injector in a Stephens County, Oklahoma Humphries Sand Unit. Injection was established through tubing into a 33 foot perforated interval 5262-5295. Decay series logs over a 24 hour period showed little definition of the zone of injection

The commencing of a positive slope just below the perforated interval during the injection

run (No. 1) seems to indicate the bottom of injection at that point. The decay series (actual measured temperatures) displayed the point of slope change downward to 5305, with the reduced rate of temperature recovery apparently extending from 5280 to 5305. Recovery rates toward ambient formation temperature above the zone were retarded by vertical averaging effects, eliminating the use of normal gradient as an established reference index.

Extrapolation of decay data from runs 1, 2, and 3 defines the zone of injection extending from approximately 5295 to 5314, at the base of the sand segment. Extrapolation of data to the cut-off point as defined by formula (1) was not accomplished with the 24 hour extrapolation, indicating further extrapolation to be necessary. The 48 hour extrapolation defined the zone prominently but did not extend to complete recovery above and below zone.

Extrapolated digital data disclosed information that could not have been defined by long term investigation, since the temperature recovery in gas injection zones is more rapid than that of water zones. Had sufficient time been allowed for optimum recovery of non-injection zones, the zone of injection also would have nearly recovered. Very slight anomalous conditions would have been available for interpretation (observe recovery actual run No. 5).

Figure 8 demonstrates the use of digitally computed temperature logs in a well that incorporates an inaccessible injection zone. This dual water injector is injecting into two strata, through tubing into the lower, and annular injection into the upper. The two zones are separated by a packer.

Decay curves run over a 24 hour period indicate that the vertical extent of the zones is much greater than determined by the 24 and 48 hour extrapolations. There is a zone, 7490-7510, that shows abnormally rapid recovery rate. These effects serve to confuse the data derived by actual logging by creating a negative slope above the actual zone of injection.

Extrapolation data projects the non-injection zones above 7542 to normal gradient, irrespective of the varying rates of recovery, and identifies actual zone of injection, 7542-7578. Influence of the packer seen on the actual curves is eliminated. The additional perimeter cooling observed in the lower zone, 7665-7680, is shown to be a non-injection zone, even though the injected fluid is leaving the well-bore through all perforations, 7628-7680. Since both zones are accepting 100% of the applied injection, no proportional distribution breakdown is indicated. Determination of the thickness of the injection zone allows for proportioning of the residual accumulative cooling observed in the bore-hole opposite each zone. The initial recovery rate opposite each depth is dependent upon the temperature of the immediate surrounding field and the heat supply for recovery.

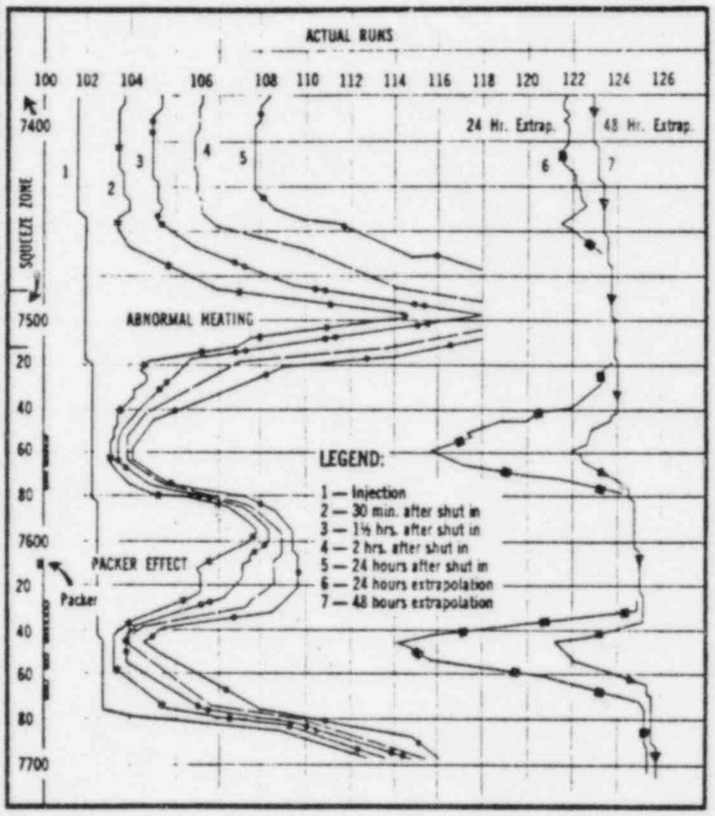


Fig. 8 - Annular Injection Temperature Survey

The heat source for recovery rate of non-injection zones is established at some finite radius; therefore, the heat for recovery opposite injection zones also must be considered at this radius. (Fig. 9)

The cooling effected at the established radius is dependent upon the ambient to injection ΔT and rate of fluid progression from the bore-hole to this radius. For example; equal volumes of fluid at the same temperature moving through identical zones (thickness porosity, etc) arrive at any finite radius with the same ΔT ratio with respect to ambient formation temperature (with some correction for diffusivity). This provides a temperature source at that radius for recovery in the bore-hole that is equal in influence. The initial rates of recovery observed would project to the radius source temperature at the same time in both intervals.

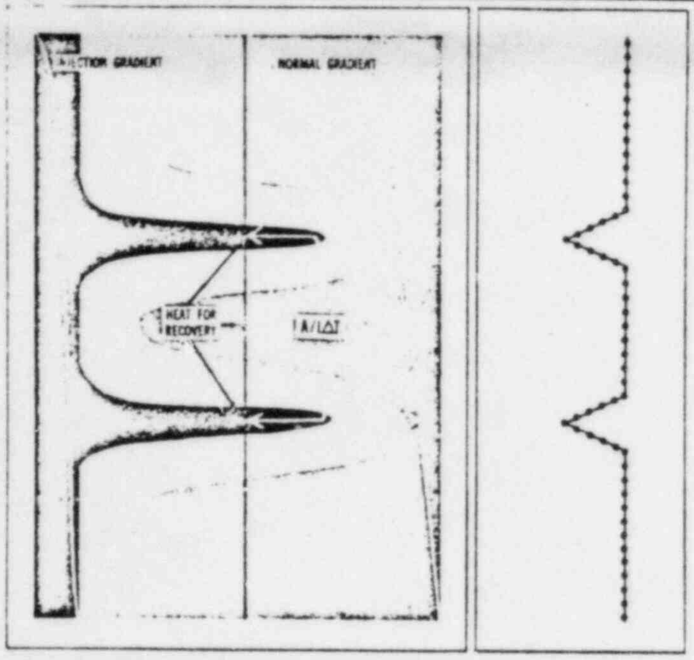


Fig. 9 - Heat for Recovery Opposite Injection Zones

Fluids moving through identical zones in disproportionate amounts vary in velocity through formation, and will arrive at the established radius with the injection ambient ΔT reflecting this same disproportion. The radial temperature sources for well-bore temperature recovery exert unequal influence and the rates of recovery vary in proportion to the unequal temperature effects.

These data can be derived from well-bore readings only if the vertical heat influence is disregarded. The digital method of recording and extrapolating from initial shut-in data minimizes the vertical heat effects observed in the ultimate result and can be considered as reflecting only lateral heat transfer effects.

The residual ΔT at the extrapolated optimum recovery time then reflects the temperature at the established equilibrium radius during injection. Since the temperature at the formation faces can be considered constant under injection conditions, the A/I ΔT relationship at equilibrium radius depends upon fluid velocity through the formation. The A/I ΔT then becomes a function of zone thickness and relative distribution of injection fluids.

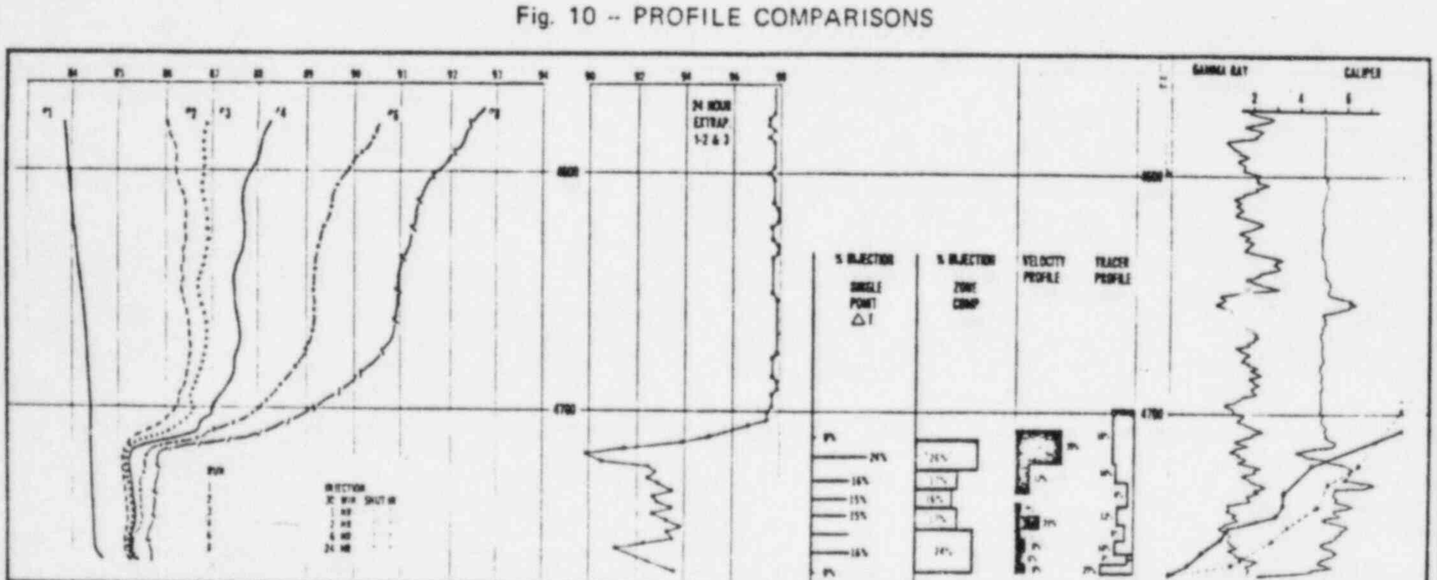
The temperature at a given radius can be predicted under uniform conditions, and any variance is considered proportional to fluid distribution between the zones. The zone compensated ΔT is derived by measurement of the magnitude of residual cooling indicated by the extrapolated temperature curve (lateral deflection of the curve) and the thickness of each zone being evaluated. The predicted ideal ΔT is calculated for each zone assuming the fluid distribution is proportional to zone thickness. The ratio of disparity between actual (compensated) ΔT and predicted ΔT is then used to adjust the fluid proportioning in each zone.

Figure 10 presents graphic representation of analog charts of actual logging runs, single point A/I ΔT, zone compensated distribution, and radioactive profiles derived by two methods.

The radioactive surveys reflect the difficulty in acquiring profiles in shot holes and highly irregular bore-holes, but comparison of the profiles derived by separate methods identifies the major zones of fluid loss. Disagreement over short intervals is due largely to the mechanics of spacing inherent in each of the techniques.

Temperature decay series (actual measurement) curves define the gross interval of injection quite prominently, with the exception being

Fig. 10 -- PROFILE COMPARISONS



that the injection seems to extend past logging depth. (Note no apparent heating at bottom of log). Twenty-four hour extrapolation based on the digital data from runs 1, 2, and 3 shows the differences in residual cooling expressed as ΔT from normal gradient at each sampling point. Extrapolation should have been carried one step further (40-48 hours) for more complete recovery of non-injection zones, but the ΔT in the injection zones will remain in proportion. Since the total injection zone is visible, the percentages represented on the bar graph are merely the proportioning of the residual ΔT at each depth.

The 16% reading at approximately 4752-54 is not representative of the total cooling effected in this zone, due to the pilot computer scanning program. The point of maximum cooling was skipped and the depth immediately above it was selected. The point of maximum cooling calculates 21%.

The zone corrected profile more nearly represents the formation fluid distribution over intervals although the thin zones are not defined prominently.

Good agreement with the total interval distribution is apparent when the increments defined by the RA profiles are included within the zones represented by the temperature definition.

Multiple zones still have an added correction factor to be applied to compensate for the additional cooling of the "sandwiched" zones under injection conditions. (Figure 11)

The reduced heat in the thin injection zones adjacent to those accepting injection does affect the radius temperature. These effects have not yet been programmed; therefore, percentages of residual cooling indicated in closely sandwiched strata represent the fluid distribution some portion higher than actually exists. Proportions are more representative of true distribution when an obvious zone separation is observed on the extrapolated temperature curves.

CONCLUSIONS

Digitally recorded and computer extrapolated temperature logs do provide data for precise definition of zones of injection. These methods of recording and techniques of logging gather data which can be supported by calculations based on known principles. Valid quantitative evaluations of temperature logs is within the scope of the immediate future.

There are many factors which tend to confuse the gathering of these data that have not yet been compensated in the present logging techniques, but continued experience will indicate methods to minimize these effects.

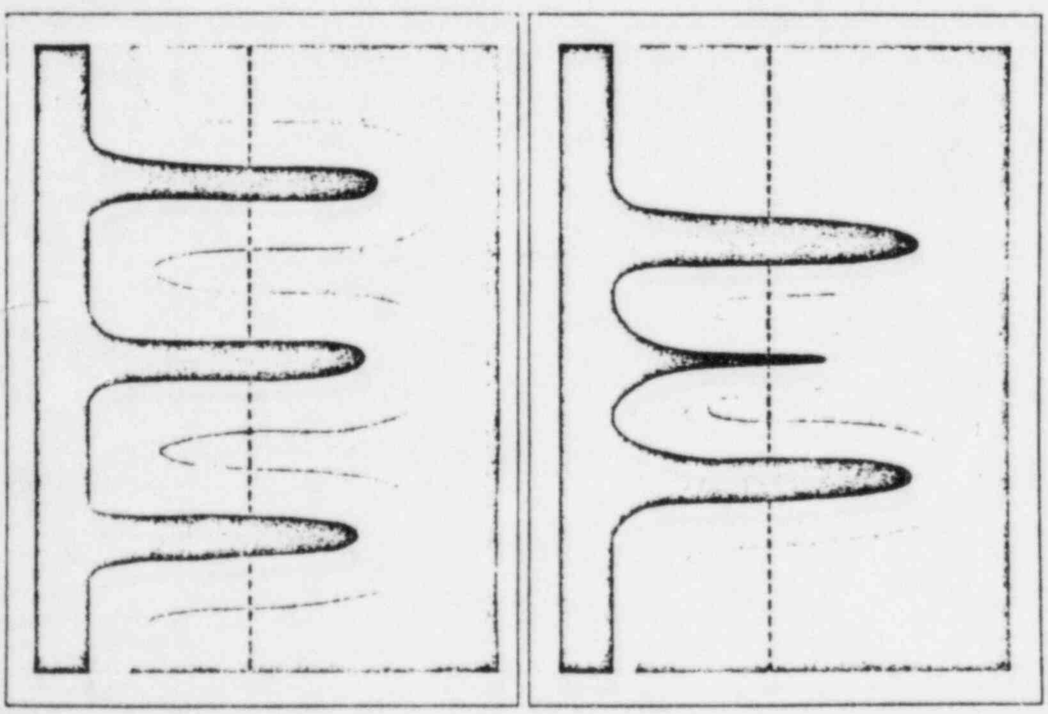


Fig. 11 - Thin Zone Condition

REFERENCES

1. Dr. Paul B. Crawford, Texas A & M University, College Station, Texas. Personal consultation.

2. M. Schlumberger, H. G. Doll and M. Perebinossoff. "Temperature Measurements in Oil Wells", 172 Meeting Institute of Petroleum Technologists, November 10, 1936.

3. H. Guyod "Temperature Well Logging", Oil Weekly, October 21-28, November 4-11, December 2, 9 & 16, 1946.

4. T. J. Nowack "Estimation of Water Injection Profiles from Temperature Surveys", AIME, October 23-24, 1952.

5. J. M. Bird "Interpretation of Temperature Logs in Water and Gas Injection Wells and Gas Producing Wells", Producers Monthly, August, 1954.

6. Jon T. Moss and Phillip White "How to Calculate Temperature Profiles in a Water Injection Well". Oil & Gas Journal, March, 1959.

7. H. J. Ramey "Well Bore Heat Transmission" 36th Meeting, SPE, October 8-11, 1961.

8. H. M. Bullard, R. D. Clarke, and H. D. Rush "Production Logging as Applied to Post Primary Production" 5th Logging Symposium, May 13-15, 1964.

9. D. R. Peacock "What You Can Learn From Temperature Logs" Petroleum Engineer, September, 1965

10. B. G. Agnew "Evaluation of Fracture Treatments with Temperature Surveys", SPE, October 3-6, 1965.

11. Howard and Fast, API Drilling & Production Practice 1957.

12. Marx and Langenheim AIME Trans., Volume 216 (1959).

13. Perry and Berggren, Publication in Engineering 5 (1944) 59.

14. Jaeger, J., Math. Phys., 34 (1956) 316.

15. Goldenberg, Proc. Phys. Soc., B, 69 (1956) 256.

16. Billy P. Morris and R. D. Cocanower, "Computers - To Increase the Value of Temperature Logs", SPWLA, 9th Annual Logging Symposium, June 23-26, 1968.

SOCIETY OF PETROLEUM ENGINEERS OF AIME
6200 North Central Expressway
Dallas, Texas 75206

PAPER NUMBER SPE - 2685

THIS IS A PREPRINT - - - SUBJECT TO CORRECTION

INTERPRETATION OF INJECTIVITY PROFILES IN IRREGULAR BORE HOLES

William G. Bearden, Member A.I.M.E., Pan American Petroleum Corporation, Tulsa, Okla.
R. D. Cocanower, Member A.I.M.E., The Western Company, Fort Worth, Texas
Dan Currens, Member A.I.M.E., Pan American Petroleum Corporation, Fort Worth, Texas
Mat Dillingham, Member A.I.M.E., The Western Company, Midland, Texas

ABSTRACT

Effective waterflooding requires knowledge of where the injected water is going, particularly in highly stratified reservoirs. Injection profiles are more commonly obtained using tracer velocity measurements and tracer logging techniques. The calculation of the tracer velocity method is dependent on well bore diameter information. The calipered diameter is not the true flow diameter, and the selection of the more accurate flow diameter has created inaccuracies more particularly in irregular bore holes. A common practice for velocity profiles was to avoid irregular well bore sections and limit the readings or stations to more uniform areas. This practice limited the definition of zones of injection.

To provide more accurate and complete injection profiles, a test well was designed with uniform and non-uniform well bore sections. Accurately metered outlets were located at areas of well bore diameter changes and in uniform pipe sections. Profiles were constructed using both the tracer-velocity and tracer logging techniques with a variety of injection rates. Comparisons of the survey results with the actual flow rates provided information to define the problem and correction factors to use to obtain the maximum accuracy.

The correction factors were applied to field injection well profiles using the tracer-velocity technique resulting in a noticeable improvement in the accuracy of interpretation. A suggested procedure is presented for interpretation of tracer-velocity logging methods to the industry. The application of correction charts for tracer-velocity logging will provide improved information for all sections of the well bore.

INTRODUCTION

Since the first usage of injection and production profiles using tracer velocity logging techniques with the interpretation method based on hole diameter information, there has been difficulty in obtaining reliable information in irregular bore holes. The major areas of difficulty have been in the vicinity of hole size changes.

A typical example of the errors of calculated velocity data is shown in Figure I.

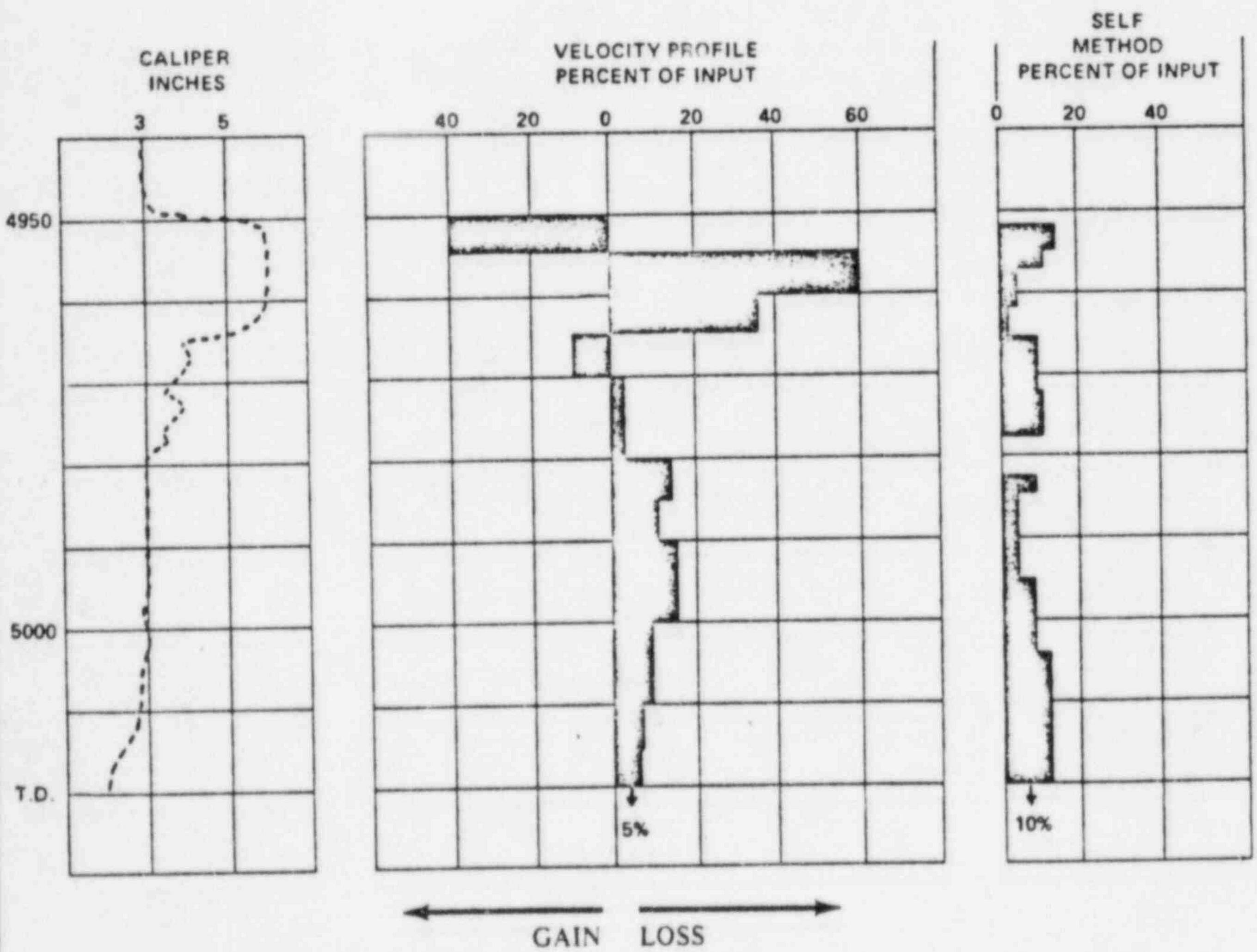
The velocity measurements recorded from 4950 to 4970 were in a section of non-uniform diameter well bore as shown by the caliper survey. The usual practice was to delete the erratic velocity data and construct an average profile through this section or use the Self Profile to determine the fluid losses.

The primary purpose of the study herein reported was to investigate the influence of hole diameters and hole diameter changes on the validity of tracer ejector readings. The secondary purpose was to investigate the accuracy of profiles in an irregular-shaped hole from which known leak-off rates could be established as determined by the tracer velocity technique and "Self Profile Method." - Ref. 1

TEST EQUIPMENT AND METHODS

The basis for this study was a series of large scale tests performed at the Pan American Research Center, Tulsa, Oklahoma. Four different apparatuses as shown on Fig. 1 in the appendix were used to simulate various well bore configurations with diameters varying from approximately 4 3/4 inches to 23½ inches. Water was flowed through these apparatuses at various rates and controlled leak-off points were installed at selected sections of the apparatus. A 1-3/8" standard tracer ejector tool with dual gamma ray detectors was used to make readings at various locations in the cells. These readings were then converted to flow rates and compared to the actual flow rates which were simultaneously being metered.

FIGURE I



Two types of profiling techniques were investigated during this study. The first technique, the tracer velocity profile, involved the ejection of a small volume of water-soluble radioactive tracer material into the flow stream, then observing the length of time required for the material to pass two detectors spaced five feet apart. This time is an inverse function of the fluid velocity which may be converted to rate by knowing the hole diameter using Equation 1.

The second method investigated was the "Self Profile Method." This method measures the radiation intensity of a moving slug of radioactive material in the bore hole. As water is lost to the formation, a decrease in intensity is observed providing information for constructing an injection profile independent of hole diameter.

TEST PROCEDURES

The first series of tests were performed on the apparatus as shown in Fig. 1A of the appendix. Metered water flow entered at the top and exited at the bottom. The tracer ejector tool was stationed at five different locations in the apparatus and velocity readings recorded at several different metered flow rates. A total of 43 readings were made as shown on Table 2 of the appendix.

The second series of tests were performed in the apparatus as shown in Fig. 1A of the appendix. The metered straight through flow was held constant and 48 velocity measurements were made at different depths as shown in Table 3 of the appendix as bursts 44 through 91.

The third series of tests were similar to the previous tests using the apparatus shown in Fig. 1B in the appendix. Fifty-one velocity measurements were made and are shown as bursts 92 through 142 on Table 4 of the appendix.

The fourth series of tests utilized the apparatus shown as Fig. 1C in the appendix. Twenty-eight velocity measurements were made with straight through flow and are shown as bursts 147 through 174 on Table 5 of the appendix.

The fifth series of tests utilized the apparatus as shown as Fig. 1d in the appendix, with flow from bottom to top. The tracer ejector tool was reassembled with the detectors on top and 20 ejections were made shown as bursts 230 through 249 on Table 6 of the appendix.

The final series of tests were run in the apparatus as shown in Fig. 1C in the appendix, and had controlled leak-off at different elevations. The leak-off points at the intermediate depths consisted of four 1/2 inch holes on a single horizontal plane that were manifolded together with 1/2 inch copper tubing. Each set of holes had a single flow line with suitable valves and meters to control and measure leak-off rate.

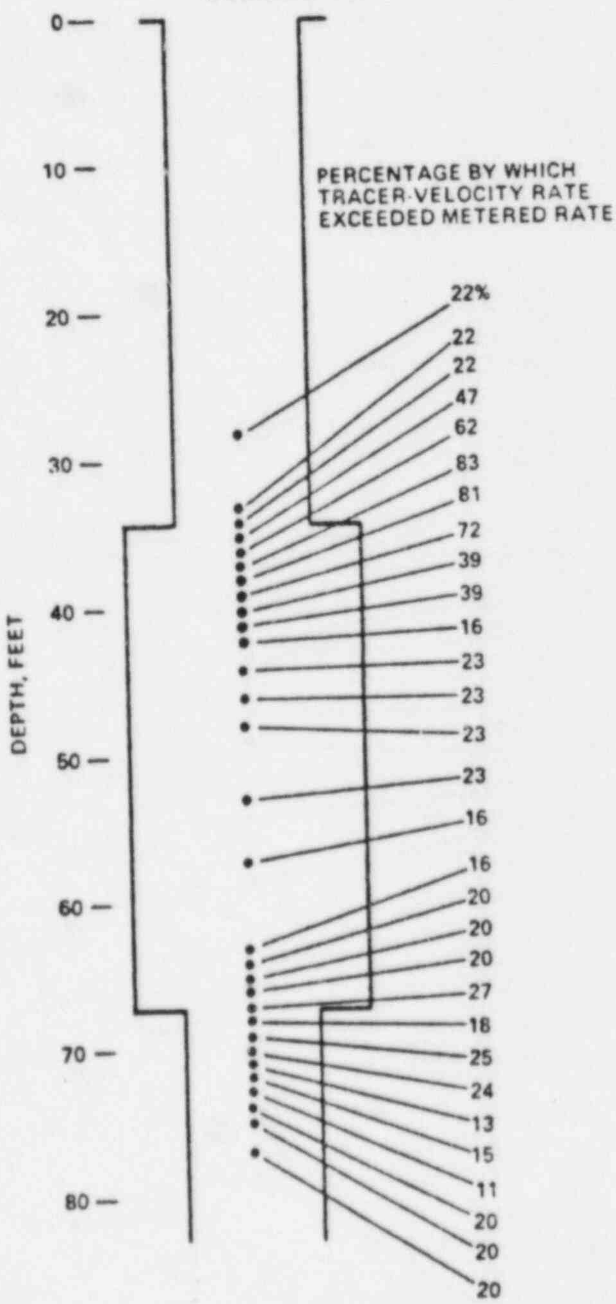
RESULTS AND INTERPRETATIONS

Tests on Influence of Hole Geometry and Validity of Tracer-Velocity Flow Rates

During this phase of the investigation, a total of 220 ejections were made at various flow rates and under various well bore configurations. The standard method was used for determining transit-times (point at which the leading edge of radioactivity departs from the base line) and the actual hole diameter, as would be determined from a caliper log. The flow rates calculated (Equation 1) from the tracer-velocity were too high in 218 instances. The average error was 117%.

A study of these individual ejections was then undertaken to determine which factors appeared to contribute to these large errors. This study revealed that the errors were nearly uniform at all locations in the hole except where the detectors were within or immediately below an abrupt hole diameter increase. This is graphically illustrated on Figures II

FIGURE II



This observation was not unexpected. When the top detector or even the ejector is in a small-diameter section of the hole, the tracer is ejected into a high velocity stream and passes the first detector at a high velocity. This velocity is not reduced for some distance after the stream passes into the larger hole because of the nozzle effect of the small pipe.

A similar but opposite effect was expected when logging in the vicinity of a hole diameter decrease; however, a study of the individual ejections tabulated in the appendix reveals that the errors under these conditions are basically no larger than when logging in relatively uniform diameter sections of the hole. That is, when the top detector is in a large-diameter hole and the bottom detector is a smaller hole, the equivalent hole diameter is the diameter of a cylinder of uniform diameter of the same volume as the hole section being considered. This is equivalent to the square root of the weighted average of the squares of the diameters. In the standard interpretive procedure, equivalent diameters per se are not calculated as they merely utilize interval capacity in barrels; however, the two methods are equivalent.

The hole diameter increases investigated in this series of experiments were as follows: (a) 5.012 to 7.921", (b) 5.012 to 11.084", (c) 7.921 to 11.084", and (d) 4.892 to 23.625". The flow rate or linear velocity must have an effect on how rapidly the nozzle effect disappears; however, the data collected were not sufficient to isolate this effect. The ratio of the hole diameters was found to be the controlling factor.

FIGURE III

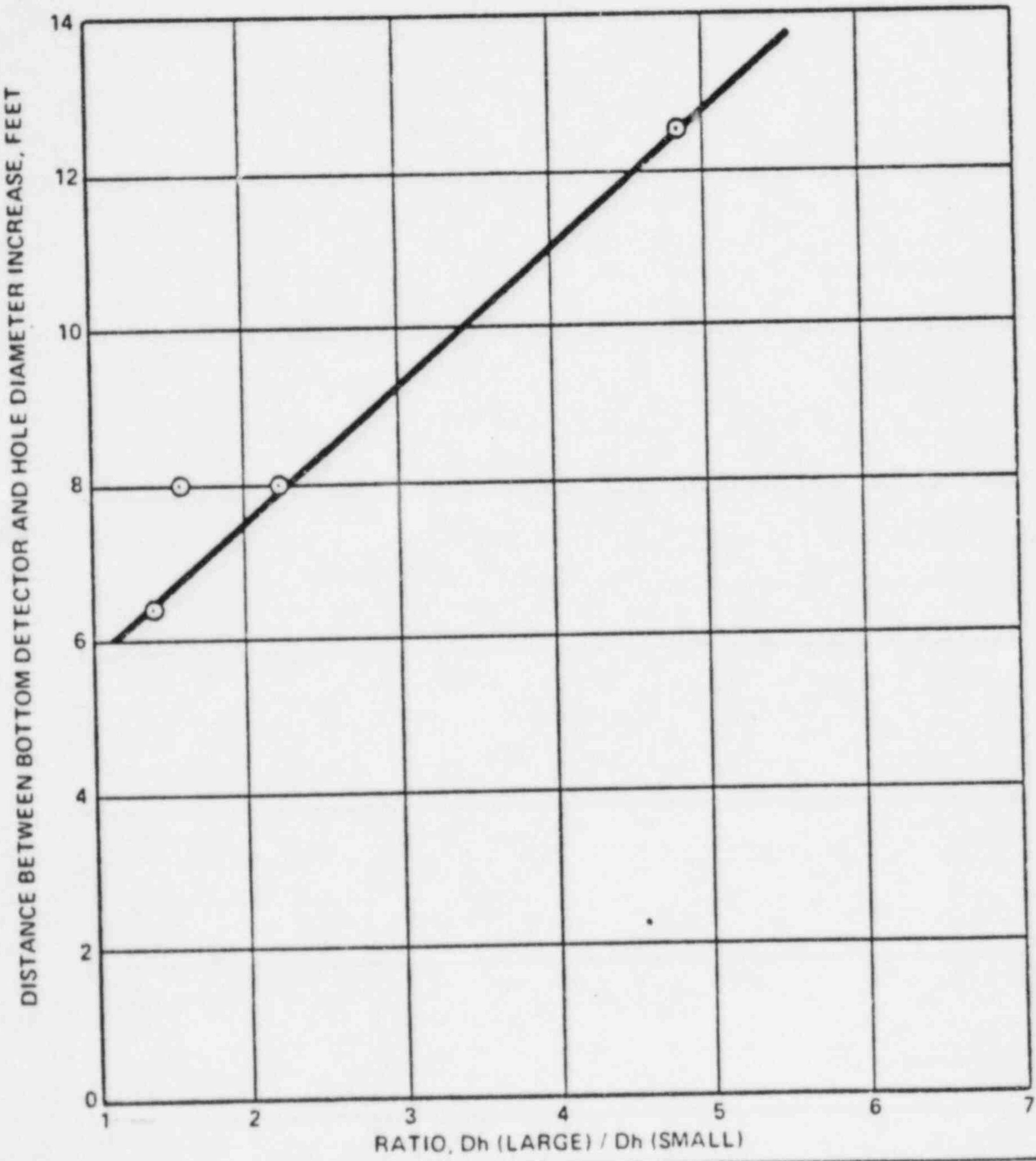


Fig. III shows a plot of the distance that the bottom detector must be below a hole diameter increase as a function of the diameter ratio in order for the effects of the increase to disappear. This plot shows that if the hole diameter increases abruptly from 6 inches to 15 inches (ratio of diameter equals 15/6 = 2.5), the bottom detector must be approximately 8½ feet below this increase to observe reliable data.

The pronounced effect of a hole diameter increase may be clearly seen by separating the 220 ejections on the basis of Fig. III. A total of 184 ejections were made in which the distance between the bottom detector and a hole diameter increase exceeded that indicated by Fig. III. These shots then were not under the influence of a hole diameter increase. The flow rates indicated by the tracer-velocity (using the actual caliper diameter) were too high in 182 ejections; however, the average error was only 24.4%. Thirty-six ejections were made at locations nearer the hole diameter increase than shown on Fig.III. The flow rates calculated from the tracer-velocity were all too high and the average percent error was 589%. As expected, the largest errors were observed when logging immediately below the most severe hole diameter increase (4.892 to 23.625").

Several conclustions can be drawn from these observations. First, if the actual hole diameter is used to compute the flow rates from tracer-velocity data when the transit times are picked by the standard method, the rates will always be too high. Secondly, the errors between the rates indicated by the tracer-velocity data and the true flow rates are nearly uniform in all hole configurations except where the detectors are within or immediately below an abrupt increase in hole diameter. To avoid large errors, the distance the bottom detector must be from the hole diameter increase was found to vary directly with the ratio of the hole diameters; varying from 7.5 feet at a twofold diameter increase to 11 feet at fourfold increase in diameter. At a distance closer to a diameter increase than indicated by the above relationship, the errors resulting from the use of the actual hole diameters are so large that the readings are meaningless.

The extreme bias of the flow rates calculated by use of the actual hole diameters (the rates were too high 218 times out of 220) suggested that the data were not being properly observed or applied. Accordingly, studies were made to re-interpret the data to see if a method or methods could be devised that would cause the errors to be more normally distributed around zero. Because of the large differences in the errors where the readings were strongly influenced by a hole diameter increase, these readings were isolated and treated independently.

Ejections Not Under the Influence of a Diameter Increase

As previously mentioned, there were 184 shots not under the influence of a hole diameter increase. The flow rates of these shots were too high by an average of 140 bpd or 24.4%. Table 1 presents a summary of the statistical analyses performed on the errors using the standard method of interpretation. It is seen that the average error is excessive, and if data points with errors greater than 50 bpd are rejected, only 5.4% of the shots would be considered reliable. Also shown on Table 1 are similar values for other procedures described in the following portions of this paper.

TABLE 1

Statistical Summary of Interpretive Methods for Re-Analyzing Those Shots Not Under the Influence of a Hole Diameter Increase

Method	Avg. Error bpd	Avg. Error Percent	Error Variance	Percent of Shots With Errors Less Than 100 bpd	50 bpd	25 bpd
Standard Procedure	-140	24.4	7,863	32.6	5.4	2.2
Reynolds Number Correction	+ 57	7.5	4,914	80.4	56.0	23.9
Peak-to-Peak Transit Times	- 15	5.5	16,411	63.3	38.5	13.8
Empirical Correlations						
First Order	0	0	4,858	91.8	68.5	53.3
Second Order	0	0	4,544	92.9	71.7	42.4
Third Order	0	0	3,873	90.8	74.5	45.1
Peak-to-Peak	0	0	16,569	67.9	42.2	23.9
Reynolds Corrected	0	0	3,715	94.0	73.9	51.6

The first interpretive method investigated assumed that the tracer was being picked up by the fastest moving part of the stream and was, therefore, reflecting the maximum velocity rather than the average velocity. A graphical representation of the velocity distribution around a logging tool is shown on Fig. 2 in the appendix. As the velocity distribution is a function of Reynolds Number, the values of Reynolds Number were calculated (using Equation 3 of the appendix) for each of the 184 ejections. The ratio of the average velocity to the maximum velocity was then determined by the relationship shown as Fig. 3 of the appendix and multiplied by the previously determined value of flow rate to arrive at a corrected value. The analysis of the error distribution is shown on Table 1 as "Reynolds Number Correction."

It is seen that this method makes an appreciable improvement in error distribution in that if all shots with errors greater than 50 bpd are arbitrarily rejected, 56.0% of the readings are reliable. Also, the average error was reduced to 7.5%; however, this method over-corrects the flow rates. Of the 184 shots considered, the corrected flow rate was too high only 19 times and was too low 165 times.

The third interpretive procedure considered consisted of reviewing the recorder charts and picking the transit times from the peaks of the radioactive response at each detector. This is illustrated on Figure 4 of the appendix. There were 109 ejections not influenced by a hole diameter increase where definite peak-to-peak times could be picked. Table 1 shows that while this method further reduced the average error, the variance, which is a direct measure of the scatter of the errors, showed a large increase. This is reflected by the fact that only 38.5% of the shots had errors less than 50 bpd compared to 56.0% of the shots for the Reynolds Number corrected values.

At this point, attention was directed toward investigating strictly empirical correlations to improve the accuracy of the data. Five different correlations were made with the aid of the multiple regression and correlation analysis computer program. Equations 4, 5, 6, 7 & 8 of the appendix.

The method that minimizes the scatter of the errors would be one with a minimum value for the variance, and from Table 1 it may be noted that the correlation with the smallest variance was a first order equation best fitting the plot of the Reynolds Number corrected values versus the true flow rates. This equation is shown as Equation 8 in the appendix. To apply this correlation, the Reynolds Number would be calculated, the indicated flow rate would be corrected according to the relationship shown as Fig. 3 of the appendix (Ref. 2) and then this corrected flow rate used to calculate the final flow rate by means of the empirical relationship shown as Equation 8 of the appendix.

This is a rather tedious procedure and does not seem justified in view of the fact that the third order correlation between the flow rate indicated by the trace using actual hole diameters and the metered rates is about as good and much easier to apply. This empirical correlation is given as Equation 6 of the appendix and is shown graphically as Fig. IV of this report. This correlation will cause approximately 75 percent of the ejections to have errors less than 50 bpd and since the error mean is zero, the average of a large number of readings should give flow rates quite close to the true rate.

As this correlation contains a negative term in which the flow rate is raised to the third power, the curve shown as Fig. IV should not be extrapolated beyond the values shown, nor should Equation 6 of the Appendix be applied to flow rates outside the range of rates specifically considered in this report.

Ejections Under the Influence of a Diameter Increase

The method presented above is believed applicable to all locations in a well except where the bottom detector is closer to a hole diameter increase than defined in Fig. III. In most wells, such areas can often be avoided; however, in some wells, reliable data near a hole diameter increase is quite important. Considerable study was devoted to the 36 data points within or immediately below a hole diameter increase.

Peak-to-peak transit times were available on 25 of the 36 ejections near a diameter increase. The errors of these 25 shots using peak-to-peak transit times were compared with the errors using the standard method of picking transit times. This comparison is shown as Table 7 of the appendix. It revealed that while the peak-to-peak method made a significant improvement in results, the errors were still excessive (an average of 385%) and were still heavily biased.

FIGURE IV

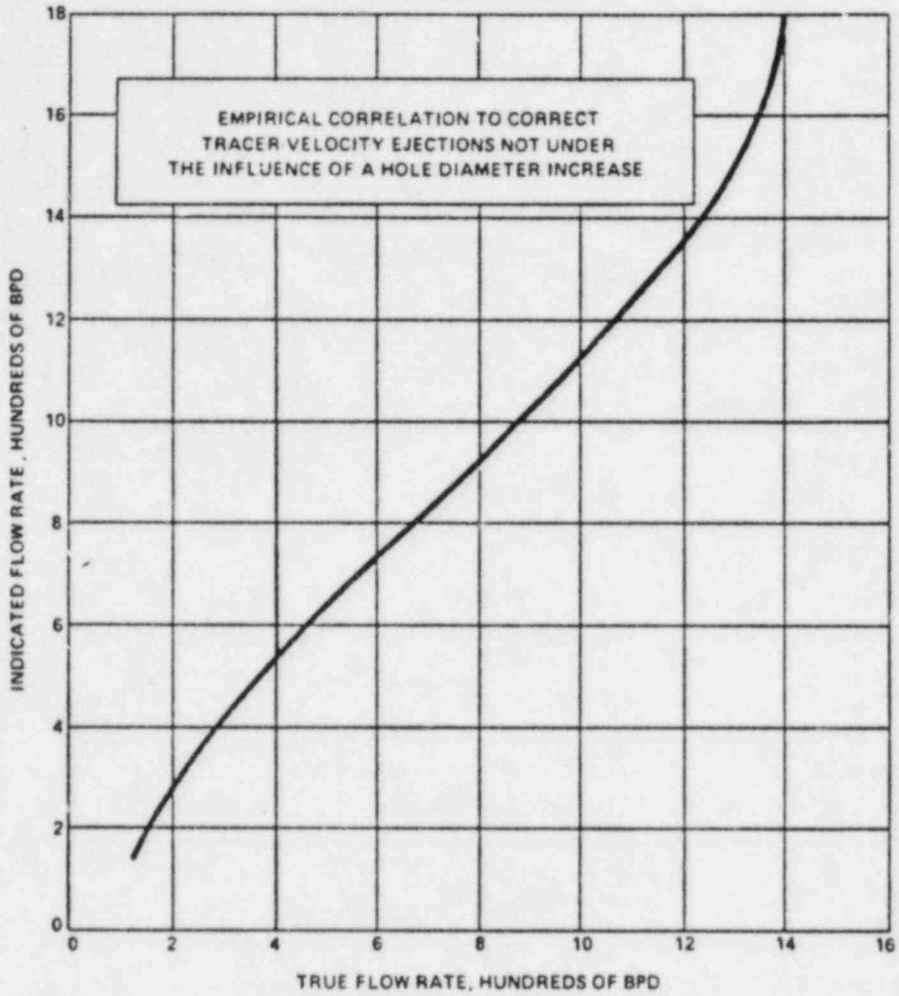
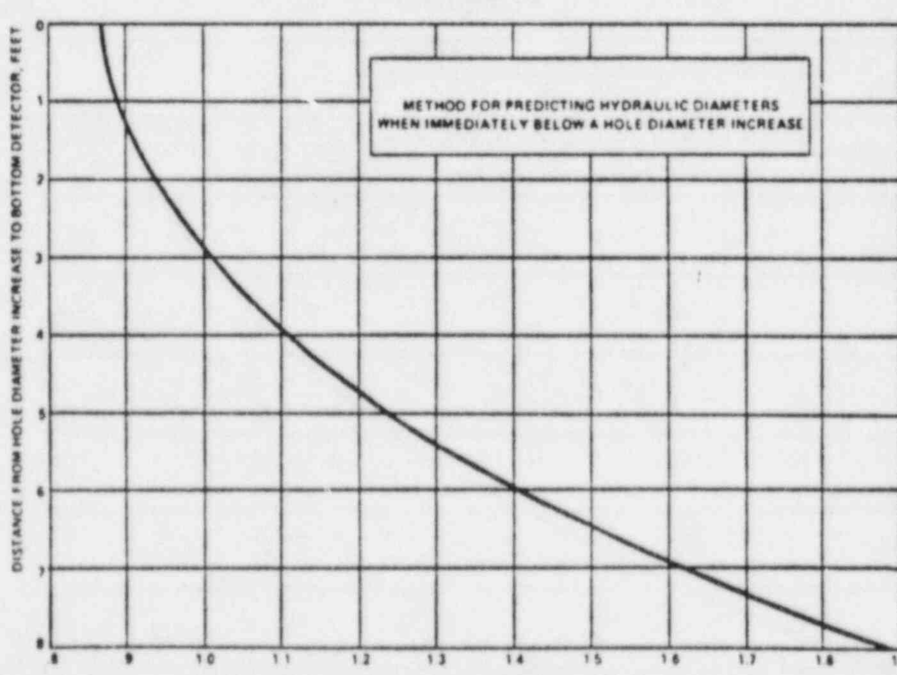


FIGURE V



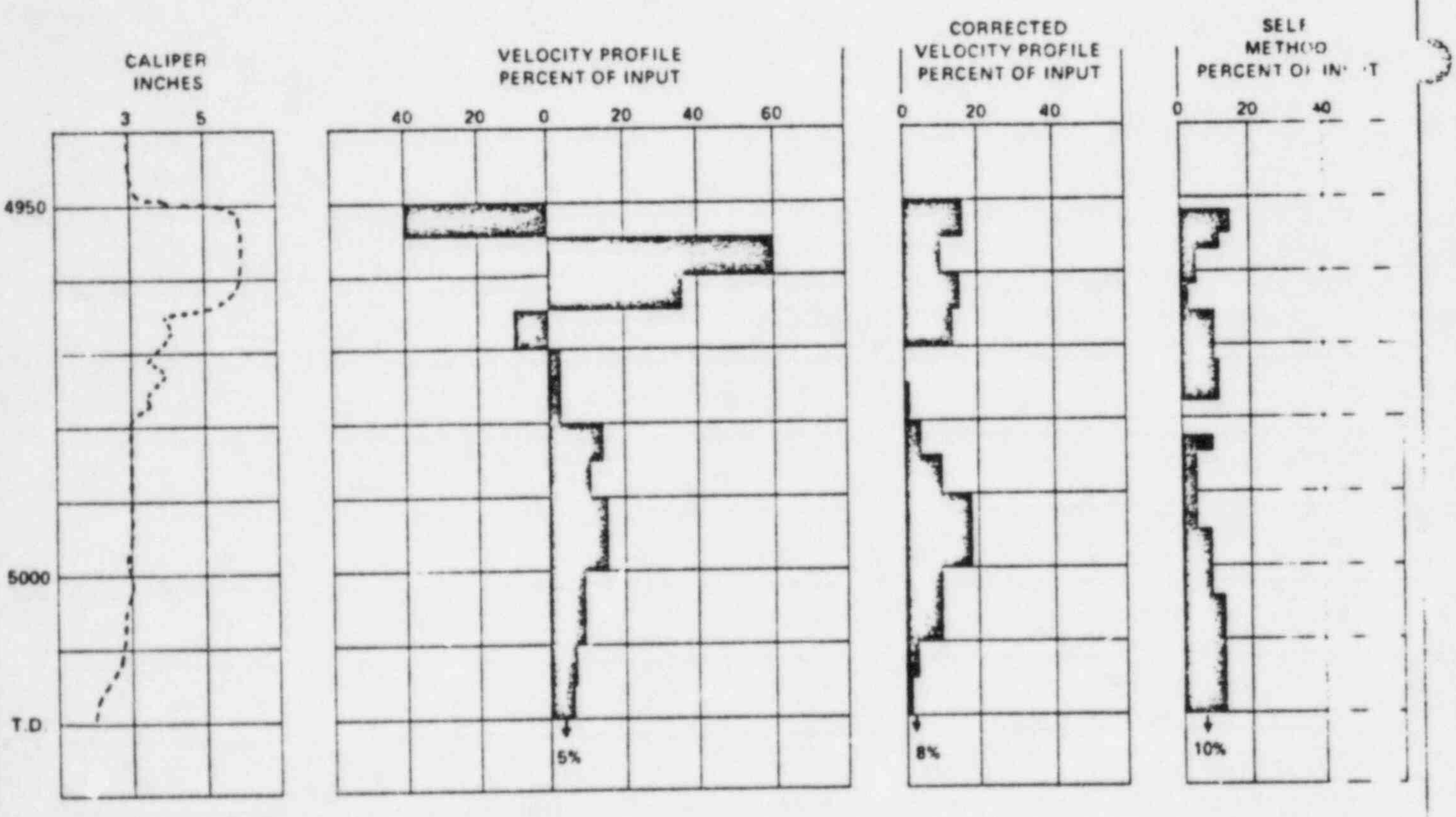
Numerous other attempts were made to relate velocity flow rates, etc., with distance to devise a method for predicting hydraulic diameters; however, the relationships were quite vague and erratic. The most secure relationship derived is that shown on Fig. V, which is a plot of distance from the hole diameter increase versus the ratio of the hydraulic diameter to the diameter of the smaller section of hole. By knowing the location of the tool and the diameter of the small hole, the hydraulic diameter may be determined from Fig. V. This hydraulic diameter is then used to calculate the flow rate from the tracer-velocity data.

This method for calculating flow rates near hole diameter increases was then applied to the 36 ejections observed in this study and compared with the true flow rates. This comparison is shown as Table 8 of the appendix. Of the 36 ejections considered, this method gave rates too high 17 times and rates too low 19 times. The mean of the errors was - 16 bpd or 4.45%; however, the errors ranged from 76.5% too high to 34.9% too low. The error variance was 43,129 and the distribution of the errors was as follows:

The error was less than 100 bpd in 55.5% of the bursts; less than 50 bpd in 36.1% of the bursts; and less than 25 bpd in 22.2% of the bursts.

By comparing these values with those shown on Table 1 for the shots not under the influence of a hole diameter increase, it may be seen that even though the method of Fig. V uniformly distributes the error around zero, the scatter is quite large and the percentage of shots with errors less than 50 bpd is fairly small. This suggests that less reliance should be placed on ejections near a hole diameter increase than on ejections made elsewhere in the hole. If such readings are required, however, the method of Fig. V should be employed. The fact that the errors are distributed around zero also suggests that duplicate settings should be made and averaged.

FIGURE VI



Suggested Interpretive Procedures

The above correlations can serve as a basis for interpreting tracer-velocity data in the field as follows:

1) Determine what ejections are under the influence of a hole diameter increase by means of Fig. III
2) If the ejection is sufficiently removed from the increase so as not to be under its influence, calculate the flow rate from the transit time picked by the standard method and the actual diameter as reflected by the caliper log. The rate so calculated should then be corrected by means of Fig. IV.
3) If the ejection is under the influence of a hole diameter increase as predicted by Fig. III estimate the hydraulic diameter from Fig. V, and calculate the flow rate from this value.

It is believed that these procedures will improve interpretation of tracer-velocity data. It should be recalled, however, that these procedures are merely techniques that cause the errors to be distributed around zero. Errors will still be observed.

The suggested interpretive procedures were applied to the profile shown in Fig. 1. The resulting profile shown in Fig. VI presented more reliable information through the areas of diameter changes.

The data presented herein can also serve as a basis for judgment in choosing between conflicting values, even after the rates are corrected by the above methods. For example, larger scatter is observed when interpreting ejections under the influence of a diameter increase. Shots further removed should therefore be given preference. Also, poor reproducibility was observed in bursts such as 96 through 99 (see Table 4 of the appendix) in which the ejector was in a large-diameter hole while the detectors were in a smaller hole. These four ejections were duplicates; yet the errors ranged from 20% too low to 20% too high. This suggests that readings of this nature be discounted. Finally, it was observed that definitive transit times are sometimes difficult to pick when the radioactive tracer becomes badly dispersed. Weak ejections and/or low flow rates cause this dispersion and such readings should be discounted.

The fact that none of the interpretive procedures eliminated all errors suggests that there are other factors affecting the readings that are not being considered. As discussed above, many of the errors noted in this study are the result of the inability of the basic data (transit time) to repeat itself under duplicate conditions. No satisfactory explanation for this is apparent; however, it is easy to visualize that centralization in the hole could have a marked affect. The tool is not centered and in small diameter holes, or in relatively uniform diameter holes, the tool would be resting against the wall. In some shots, the tracer could conceivably be ejected into the faster stream of water while in others it may be directed more toward the wall of the hole. Also, it is possible that under certain conditions, the tool could be swaying in the stream of water in a manner similar to flutter of a structural member.

Evaluation of Profiles

The final phase of this investigation consisted of tests to determine profiles under controlled leak-off conditions by means of the tracer-velocity technique and by the "Self Profile Method". The logging personnel did not know the location of the leak-off points and they were given no recommendations as to the number or location of ejections that should be made. Finally, since these profiling tests were made at the same time as the data previously discussed were collected, the correlations and judgment gained from this study were not applied to the profiling tests.

The results of these profiling tests are shown graphically in Fig. 5 of the appendix. The three tests involved a total of 8 separate zones of injectivity. Seven of these zones were near a hole diameter change while the other was at the bottom of the simulated well. The test conditions were, therefore, fairly severe.

The tracer-velocity technique located all eight zones of injectivity; that is, the actual zone of injectivity was contained within the interval indicated by the survey. The zones were not defined depthwise as accurately as desired, however, as the surveys generally showed the losses to be within six to ten foot intervals, whereas these were actually on a horizontal plane. Better depth definition could have been obtained by making more ejections, but since most of the zones were near hole diameter changes, ejections were limited in such locations. The analysis herein presented has shown that the errors near a hole diameter decrease are not large and more ejections in such cases could have provided reliable data.

As expected, the tracer-velocity data indicated flow rates appreciably higher than actually imposed; however, the zonal leak-off expressed as a percentage of the total flow was fairly accurate.

All zones of leak-off in these three tests were also bracketed by the intervals located by the Self Method. In the one test with loss at the bottom, the Self Method indicated the loss to be in the lower 28 feet of hole. When the loss is near the bottom of the hole, a tracer slug ejected near the top becomes quite dispersed as it moves down through various hole configurations. When it enters a smaller hole near bottom, it is dispersed even more and its velocity is increased such that only a limited number of passes through it with the logging tool can be made. Also, the inability to pick an exact depth to make an observation is a limitation of the method.

The Self Method defined the amount of flow (expressed as a percentage of total flow) into each zone fairly satisfactorily. Also, when the zones of loss were not near the bottom of the hole, the indicated zones could be made more definitive by assuming that the actual loss was in the zone of overlap from both the tracer-velocity and the Self Method.

SUMMARY AND CONCLUSIONS

A comprehensive study of tracer-velocity logging under controlled conditions of hole geometry and flow rates revealed the following:

(1) If the actual hole diameter is used to compute the flow rates from tracer-velocity data, the rates will always be too high.

(2) The errors between the rates indicated by the tracer-velocity data and the true flow rates are nearly uniform in all hole configurations except where the detectors are within or immediately below an abrupt increase in hole diameter.

(3) To avoid large errors, the distance the bottom detector must be from a hole diameter increase was found to vary directly with the ratio of the hole diameters; ranging from 7.5 feet at a two-fold diameter increase to 11 feet at a fourfold diameter increase.

(4) The bias in the errors of the shots not under the influence of a hole diameter increase may be eliminated by means of an empirical flow rate correlation. This correlation effects an error mean of zero; therefore, the average of repeated readings should approach the true rate.

(5) A method was devised to predict hydraulic diameters when surveying in locations under the influence of a hole diameter increase. This method distributes the errors around zero, but the scatter is large and such readings should be discounted.

(6) An evaluation of injection profiles obtained from tracer-velocity data and from the Self Method indicated the tracer-velocity measurements more accurately located the zones of injectivity and should be given preference. The Self Method, however, was effective within certain limits and should serve as a valuable adjunct to the tracer-velocity method.

(7) The fact that the correlations herein presented only distributed the errors around zero and did not eliminate them infers that factors not considered in this study are affecting results. Tool centralization may be such a factor.

REFERENCES:

1. Self, C and Dillingham, M: "A New Fluid Flow Analysis Technique for Determining Bore Hole Conditions", Paper No. SPE 1752, presented at SPE Symposium March 5 - 7, 1967. Fort Worth, Texas.

2. Dr. Paul B. Crawford, Texas A & M University, "Interpretation of Injectivity Profile Logging Data"; Prepared for The Western Company, Nov. 18, 1964.

EQUATIONS

Standard Method Flow Rate

$$Qi = \frac{419.656\ (D_h^2 - 1.890625)}{t_o} \quad \ldots\ldots\ldots\ldots (1)$$

Where Qi = indicated flow based on actual hole diameter, bpd

Dh = actual hole diameter between detectors, inches

t_o = observed time for tracer to pass between 5 foot spaced detectors, seconds

Hydraulic Diameter

$$HD = \sqrt{\frac{(Qm)\ (t_o)}{419.656} + 1.890625} \quad \ldots\ldots\ldots (2)$$

Where HD = calculated hydraulic diameter

Qm = true flow rate as determined by meters, bpd

Reynolds Number

$$Re = \frac{DV_p}{\mu} = \frac{(D_h - 1.375)\,(5)\,(62.4)}{(12)\,(t_o)\,(1.2028)\,(0.000672)} \quad \ldots (3)$$

$$Re = \frac{32{,}166\ (D_h - 1.375)}{t_o}$$

First Correlation

$$Qm' = 0.8766\ Q_i - 33.88 \quad \ldots\ldots\ldots\ldots\ldots (4)$$

Where Qm' is the calculated value from the empirical relationship.

Second Correlation

$$Q_m' = 1.0649\ Q_i - 9.6651 \times 10^{-5}\ Q_i^2 - 105 \quad \ldots (5)$$

Third Correlation

$$Q_m' = 69.56 + 0.2569\ Q_i + 9.1347 \times 10^{-4} Q_i^2 - 3.5804 \times 10^{-7} Q_i^3$$

Fourth Correlation

$$Q_m' = 1.00505\ Q_{ip} - 19.72 \quad \ldots\ldots\ldots\ldots (\ )$$

Fifth Correlation

$$Q_m' = 0.91194\ Q_{ic} + 5.79 \quad \ldots\ldots\ldots\ldots (\ )$$

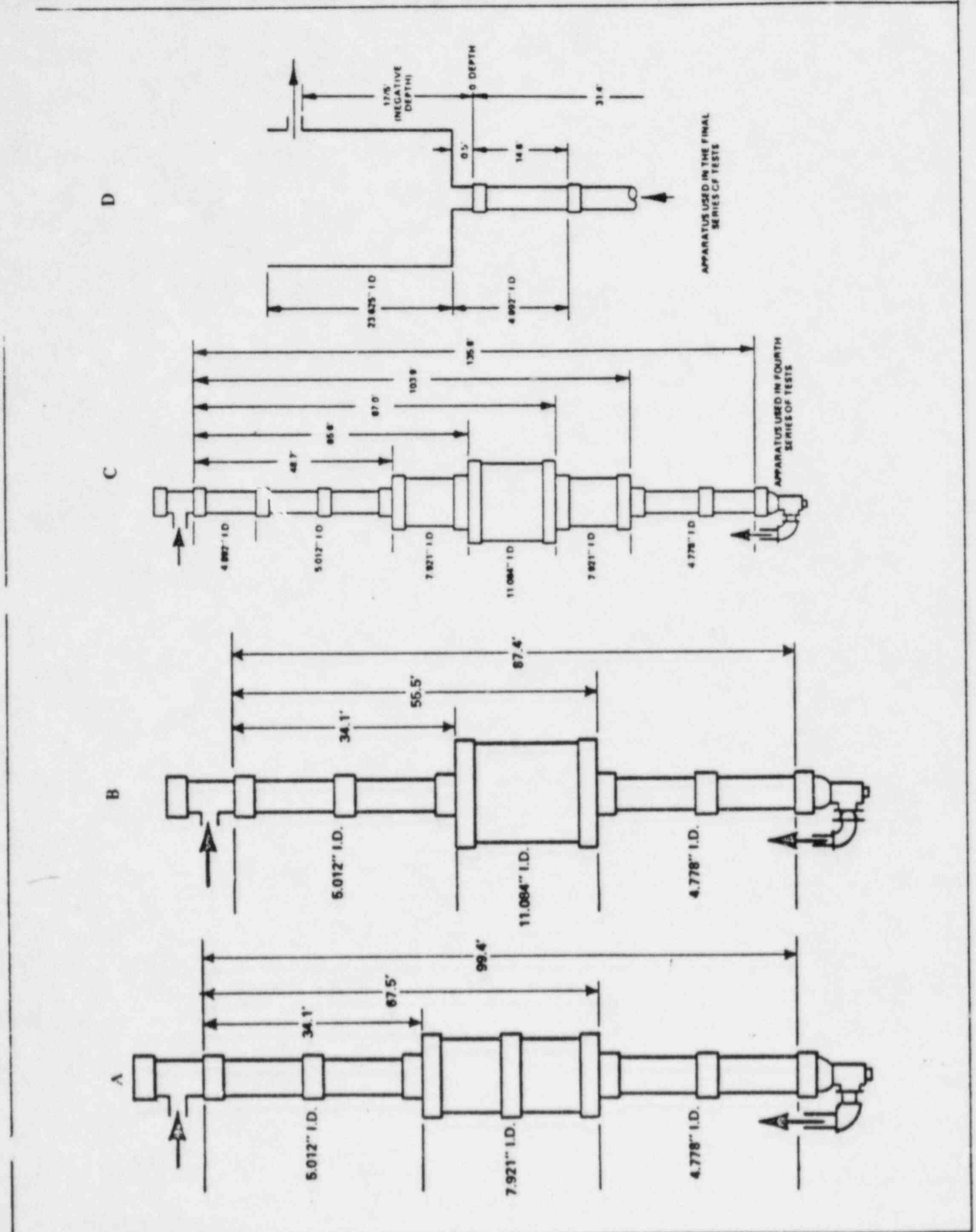
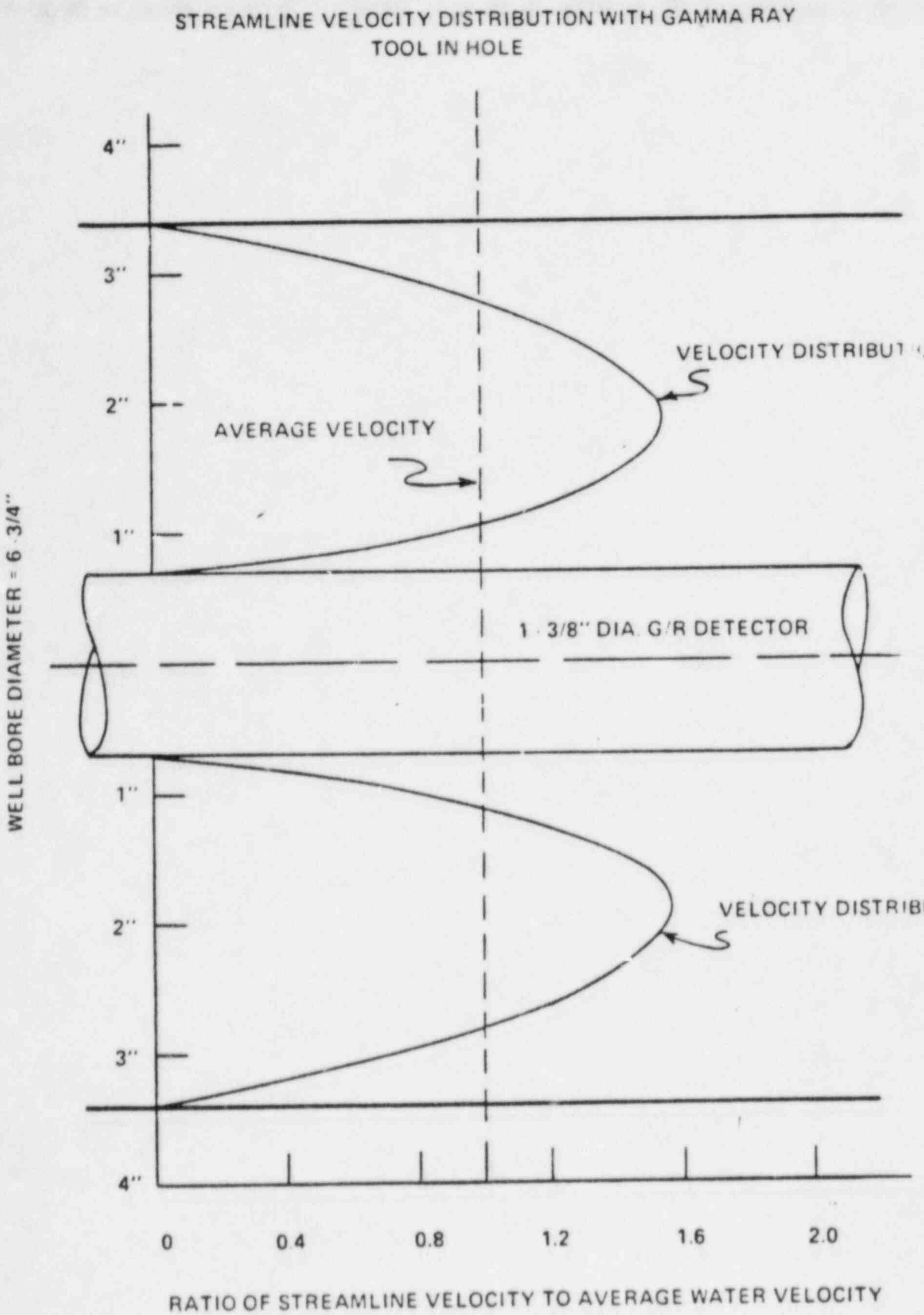


FIGURE 1 · APPARATUS USED FOR FLOW TEST MEASUREMENT APPENDIX



APPENDIX FIGURE 2

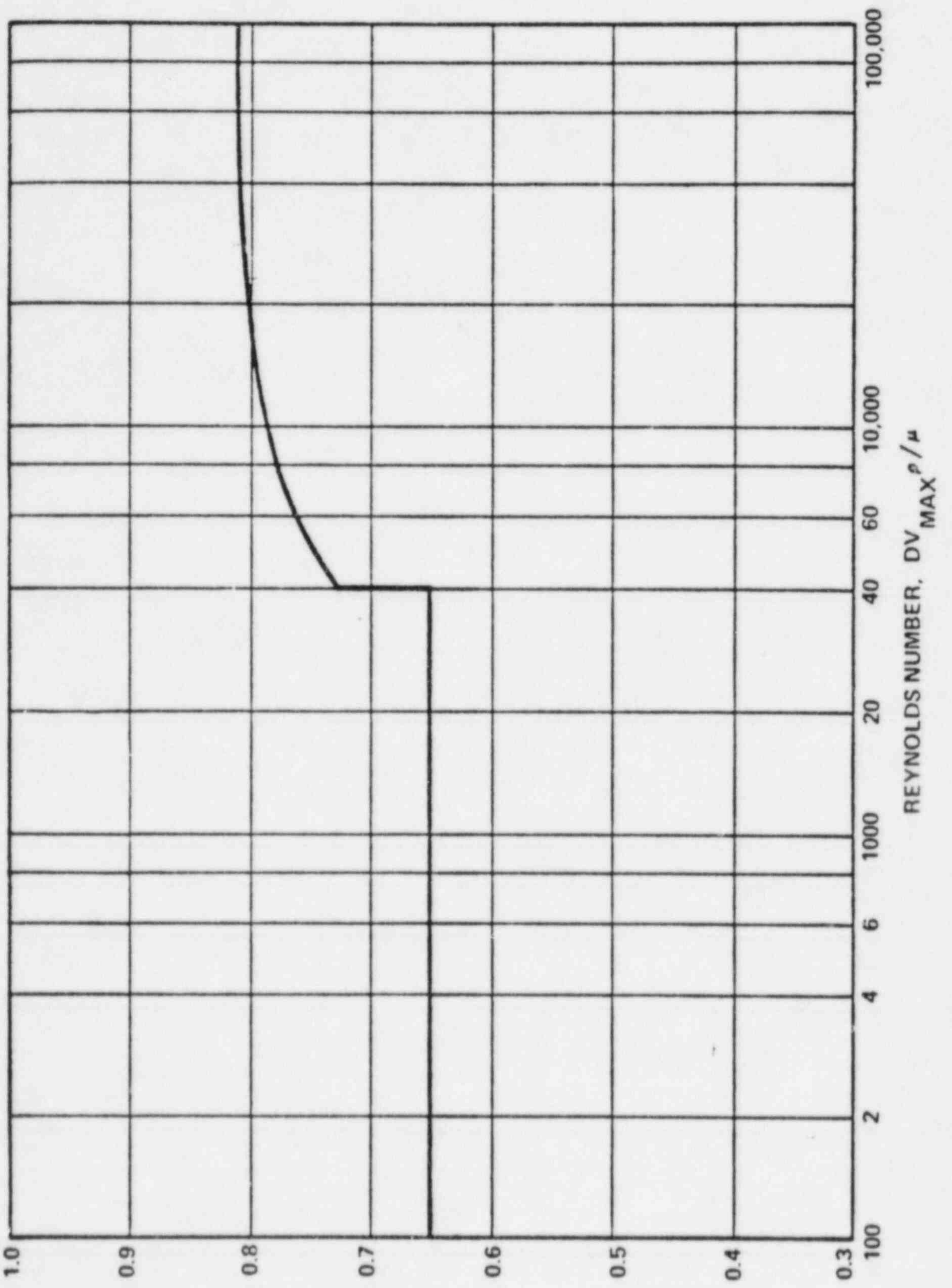
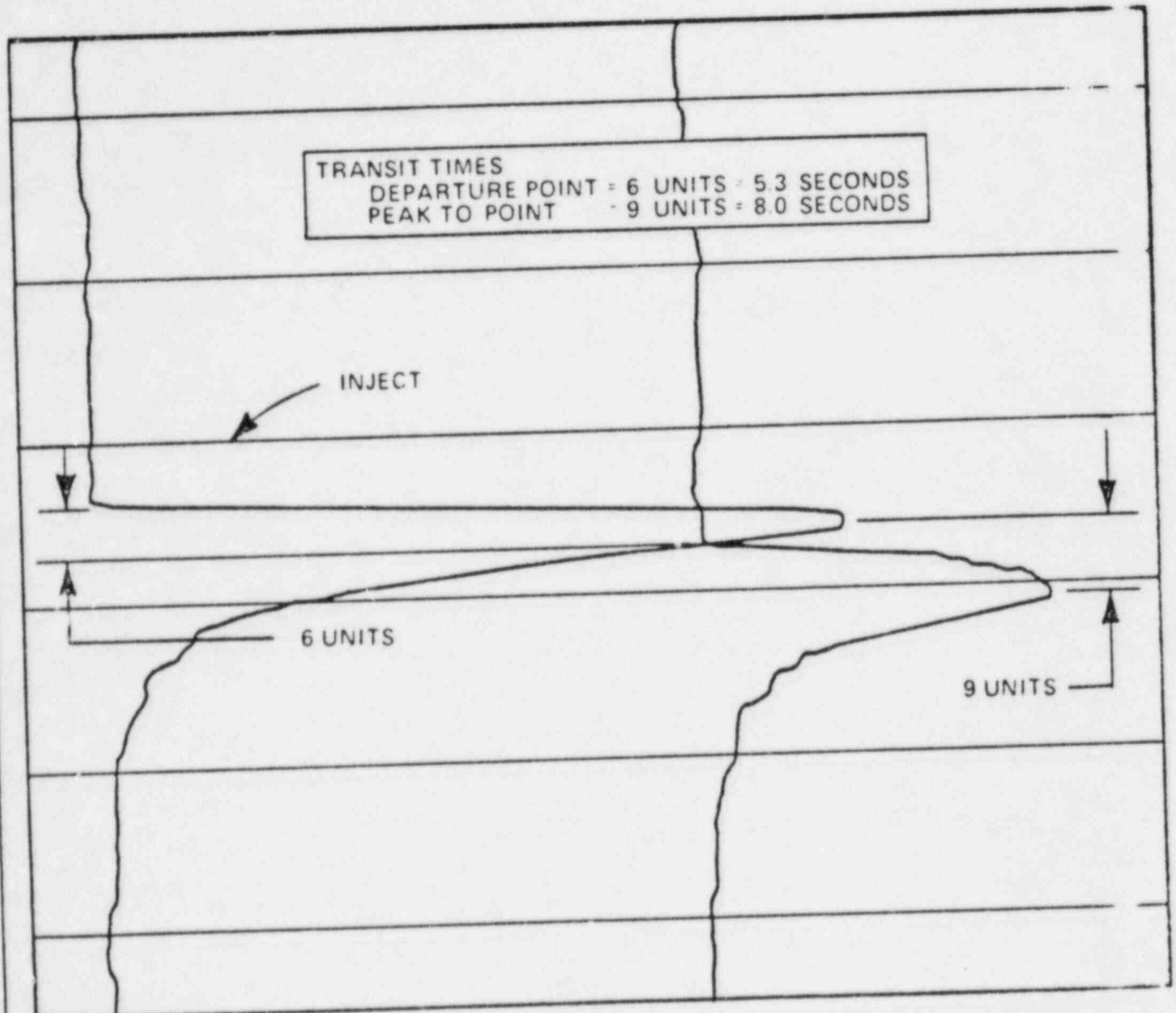

1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
V_{AVG}/V_{MAX}
100
2
4
6
1000
20
40
60
10,000
100,000
REYNOLDS NUMBER, $DV_{MAX}\rho/\mu$

FIGURE 3



APPENDIX

FIGURE 4

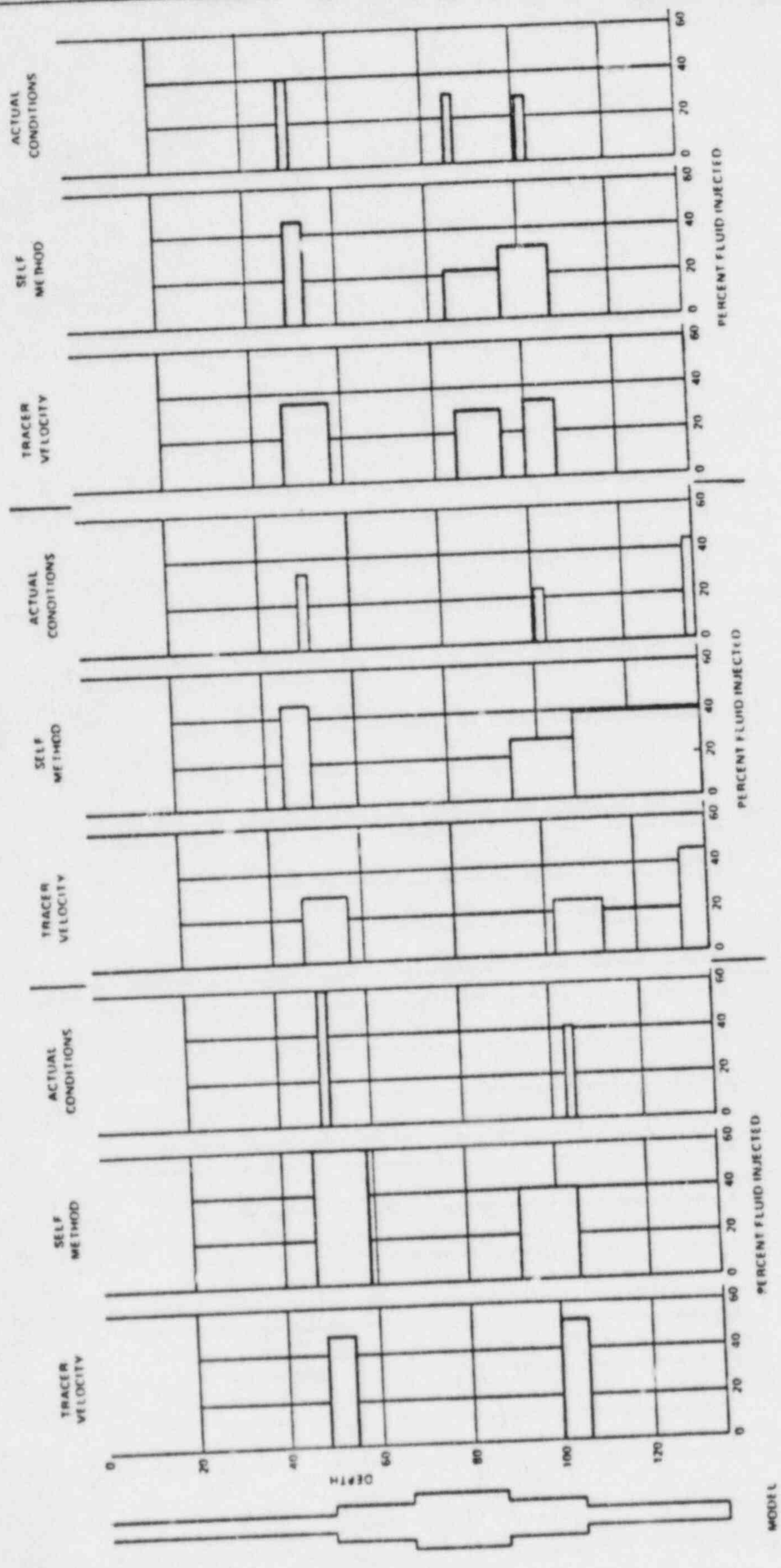


FIGURE 5

APPENDIX

FIRST SERIES OF TRACER-VELOCITY TESTS
APPARATUS SHOWN ON FIGURE 1a

Burst No.	Detector Depths 1st	Detector Depths 2nd	Hole Dia. Dh, in.	Time, t_o, sec	Flow Rate, bpd Indicated Q_i	Flow Rate, bpd Metered, Q_m	Ratio Q_i/Q_m	Hydr Dia HD, in.	[illegible]io [illegible]Dh
1	24	29	5.012	51.6	189	129	1.465	4.213	[illegible]
2	24	29	5.012	51.6	189	129	1.465	4.213	[illegible]
3	24	29	5.012	28.4	343	256	1.340	4.384	[illegible]
4	24	29	5.012	28.4	343	256	1.340	4.384	[illegible]
5	24	29	5.012	16	609	508	1.199	4.611	[illegible]20
6	24	29	5.012	16	609	508	1.199	4.611	[illegible]20
7	24	29	5.012	16	609	508	1.199	4.611	[illegible]20
8	24	29	5.012	9.8	995	827	1.203	4.605	[illegible]19
9	24	29	5.012	9.8	995	827	1.203	4.605	[illegible]19
10	24	29	5.012	6.2	1572	1319	1.192	4.624	[illegible]23
11	24	29	5.012	6.2	1572	1319	1.192	4.624	[illegible]23
12*	54	59	7.921	103	343	130	2.638	5.814	[illegible]734
13	54	59	7.921	125	204	130	1.569	6.373	[illegible]
14*	54	59	7.921	115	222	122	1.820	5.943	[illegible]
15	54	59	7.921	137	186	122	1.525	6.459	[illegible]
16	54	59	7.921	15.1	1691	1445	1.170	7.341	[illegible]
17	54	59	7.921	15.1	1691	1445	1.170	7.341	[illegible]
18	54	59	7.921	20.4	1252	1136	1.102	7.557	[illegible]
19	54	59	7.921	24	1064	974	1.092	7.589	[illegible]
20	54	59	7.921	24	1064	974	1.092	7.589	[illegible]
21	54	59	7.921	28.5	896	772	1.161	7.370	[illegible]
22	54	59	7.921	28.5	896	772	1.161	7.370	[illegible]
23	54	59	7.921	34.7	736	616	1.195	7.268	[illegible]
24	54	59	7.921	34.7	736	616	1.195	7.268	[illegible]
25	54	59	7.921	60.5	422	310	1.361	6.825	[illegible]
26	54	59	7.921	60.5	422	310	1.361	6.825	[illegible]
27	54	59	7.921	124.5	205	166	1.235	7.151	[illegible]
28	43	48	7.921	16	1596	1495	1.068	7.674	[illegible]
29	43	48	7.921	18.7	1366	1168	1.170	7.344	[illegible]
30	43	48	7.921	18.7	1366	1168	1.170	7.344	[illegible]
31	43	48	7.921	25.8	990	812	1.219	7.198	[illegible]
32	43	48	7.921	41.9	609	485	1.256	7.093	[illegible]5
33	43	48	7.921	41.9	609	485	1.256	7.093	[illegible]5
34	43	48	7.921	103	248	163	1.521	6.473	[illegible]17
35	41	46	7.921	15.1	1691	1506	1.123	7.489	[illegible]5
36	41	46	7.921	26.5	964	815	1.183	7.304	[illegible]22
37	41	46	7.921	42.6	599	485	1.235	7.150	[illegible]03
38	41	46	7.921	102.4	249	166	1.500	6.511	[illegible]22
39	37.5	42.5	7.921	44.5	574	482	1.191	7.280	[illegible]19
40	37.5	42.5	7.921	27.6	925	827	1.119	7.520	[illegible]47
41	37.5	42.5	7.921	15.1	1691	1351	1.252	7.106	[illegible]97
42	36.5	41.5	7.921	16	1596	1351	1.181	7.307	[illegible]22
43	36.5	41.5	7.921	24.1	1060	818	1.296	6.990	[illegible]82

* At these low flow rates, response at second detector is badly spread. RA departure points for determining t_o were not too definitive.

APPENDIX

TABLE 2

SECOND SERIES OF TRACER-VELOCITY TESTS
APPARATUS SHOWN ON FIGURE 1a

Burst No.	Detector Depths 1st	Detector Depths 2nd	Hole Dia. Dh, in.	Time, t_o, sec	Flow Rate, bpd Indicated Q_i	Flow Rate, bpd Metered, Q_m	Ratio Q_i/Q_m	Hydr Dia HD, in.	Ratio HD/Dh
44	72	77	4.778	10.7	821	686	1.197	4.402	.921
45	70	75	4.778	10.7	821	686	1.197	4.402	.921
46	69	74	4.778	10.7	821	686	1.197	4.402	.921
47	68	73	4.778	11.6	758	686	1.105	4.566	.956
48	68	73	4.778	11.6	758	686	1.105	4.566	.956
49*	67	72	5.179	13.3	787	686	1.147	4.861	.939
50*	66	71	5.899	17.8	776	686	1.131	5.567	.944
51*	65	70	6.541	20.2	850	686	1.239	5.909	.903
52*	64	69	7.125	24	855	686	1.246	6.413	.900
53*	63	68	7.665	29.4	812	686	1.184	7.068	.922
54	62	67	7.921	29.4	869	686	1.267	7.068	.892
55	61	66	7.921	29.4	869	686	1.267	7.068	.892
56	52	57	7.921	32	798	686	1.163	7.362	.929
57	58	63	7.921	32	798	686	1.163	7.362	.929
58	59	64	7.921	31	824	686	1.201	7.250	.915
59	60	65	7.921	31	824	686	1.201	7.250	.915
60	61	66	7.921	31	824	686	1.201	7.250	.915
61	72	77	4.778	12.5	703	686	1.025	4.725	.989
62	72	77	4.778	12.5	703	686	1.025	4.725	.989
63	72	77	4.778	12	732	686	1.067	4.638	.971
64	48	53	7.921	30.2	846	686	1.233	7.159	.904
65	43	48	7.921	30.2	846	686	1.233	7.159	.904
66	41	46	7.921	30.2	846	686	1.233	7.159	.904
67	39	44	7.921	30.2	846	686	1.233	7.159	.904
68	37	42	7.921	32	798	686	1.163	7.362	.929
69	36	41	7.921	26.7	956	586	1.394	6.748	.852
70	35	40	7.921	26.7	956	686	1.394	6.748	.852
71*	34	39	7.873	21.4	1178	686	1.717	6.072	.771
72*	33	38	7.382	17.8	1240	686	1.808	5.567	.754
73*	32	37	6.851	15.1	1252	686	1.825	5.155	.752
74*	31	36	6.278	14.2	1109	686	1.617	5.010	.798
75*	30	35	5.643	12.5	1006	686	1.466	4.725	.837
76	29	34	5.012	11.6	840	686	1.224	4.566	.911
77	28	33	5.012	11.6	840	686	1.224	4.566	.911
78	23	28	5.012	11.6	840	686	1.224	4.566	.911
79	72	77	4.778	6.2	1417	1334	1.062	4.647	.973
80	61	66	7.921	18.7	1366	1334	1.024	7.832	.989
81	55	60	7.921	17.8	1435	1334	1.076	7.647	.965
82*	34	39	7.873	11.6	2174	1334	1.630	6.226	.791
83*	30	35	5.643	7.1	1770	1334	1.327	4.946	.876
84	23	28	5.012	5.8	1[illegible]81	1334	1.260	4.509	.900
85	72	77	4.778	17.8	420	347	1.210	3.861	.808
86	61	66	7.921	56	456	347	1.314	6.819	.861
87	55	60	7.921	55	464	347	1.337	6.758	.853
88*	34	39	7.873	49.8	506	347	1.458	6.432	.817
89*	30	35	5.643	23.1	544	347	1.568	4.392	.778
90	23	28	5.012	22.2	439	347	1.265	4.306	.859
91	72	77	4.778	17.8	420	347	1.210	3.861	.808

* The tool setting at these Bursts was such that each detector was in different-sized hole. The hole diameter (D_h) is the diameter of a cylinder of uniform diameter of the same volume as the hole section being considered. This is equivalent to the square root of the weighted average of the squares of the diameters.

TABLE 3

APPENDIX

THIRD SERIES OF TRACER VELOCITY TESTS
APPARATUS SHOWN ON FIGURE 1b

Burst No.	Detector Depths 1st	Detector Depths 2nd	Hole Dia. Dh, in.	Time, t_o, sec	Flow Rate, bpd Indicated Q_i	Flow Rate, bpd Metered, Q_m	Ratio Q_i/Q_m	Hydr Dia HD, in.	Ratio HD/Dh
92	77	82	4.778	5.3	1658	1369	1.211	4.380	[illegible]17
93	65	70	4.778	5.3	1658	1369	1.211	4.380	[illegible]17
94	61	66	4.778	5.3	1658	1369	1.211	4.380	[illegible]17
95	58	63	4.778	5.3	1658	1369	1.211	4.380	[illegible]17
96	56	61	4.778	8.	1098	1369	.802	5.290	1 [illegible]07
97	56	61	4.778	5.3	1658	1369	1.211	4.380	[illegible]17
98	56	61	4.778	6.2	1417	1369	1.035	4.703	[illegible]84
99	56	61	4.778	6.7	1311	1369	.958	4.873	1 [illegible]0
100*	54	59	7.269	13.8	1549	1369	1.132	6.849	[illegible]2
101*	54	59	7.269	13.8	1549	1369	1.132	6.849	[illegible]2
102*	52	57	9.636	23.2	1645	1369	1.202	8.789	[illegible]2
103	50	55	11.084	31.2	1627	1369	1.188	10.182	[illegible]9
104	48	53	11.084	33.8	1502	1369	1.097	10.590	[illegible]5
105	46	51	11.084	33.8	1502	1369	1.097	10.590	[illegible]5
106	39	44	11.084	33.8	1502	1369	1.097	10.590	[illegible]5
107	39	44	11.084	33.8	1502	1369	1.097	10.590	[illegible]5
108	37	42	11.084	30.3	1675	1369	1.224	10.037	[illegible]6
109	35	40	11.084	22.3	2276	1369	1.663	8.639	[illegible]9
110*	33	38	10.067	11.6	3598	1369	2.628	6.303	[illegible]6
111*	31	36	7.890	7.1	3568	1369	2.606	5.005	[illegible]
112	27	32	5.012	6.2	1572	1369	1.149	4.703	[illegible]8
113	22	27	5.012	6.2	1572	1369	1.149	4.703	[illegible]8
114	77	82	4.778	5.3	1658	1369	1.211	4.380	[illegible]7
115	77	82	4.778	11.6	758	648	1.169	4.450	[illegible]1
116	56	61	4.778	12.5	703	648	1.085	4.603	[illegible]3
117	56	61	4.778	13.4	656	648	1.012	4.752	[illegible]5
118*	54	59	7.269	30.3	706	648	1.089	6.977	[illegible]9
119*	52	57	9.636	48.1	794	648	1.225	8.727	[illegible]6
120	50	55	11.084	58	875	648	1.351	9.563	[illegible]3
121	48	53	11.084	70.3	722	648	1.114	10.509	[illegible]8
122	42	47	11.084	65	781	648	1.205	10.112	[illegible]2
123	37	42	11.084	59.6	852	648	1.314	9.691	[illegible]4
124	35	40	11.084	42.7	1189	648	1.834	8.236	[illegible]3
125*	31	36	7.890	13.4	1890	648	2.917	4.752	[illegible]2
126	27	32	5.012	12.5	780	648	1.204	4.603	[illegible]8
127	77	82	4.778	11.6	758	648	1.169	4.450	[illegible]1
128 (1)	77	82	4.778	10.7	821	679	1.209	4.382	[illegible]7
129	56	61	4.778	11.6	758	679	1.116	4.545	[illegible]1
130	56	61	4.778	10.7	821	679	1.209	4.382	[illegible]7
131*	52	57	9.636	40.1	952	679	1.402	8.171	[illegible]5
132	50	55	11.084	63	806	679	1.187	10.189	[illegible]9
133	42	47	11.084	65	781	679	1.150	10.347	[illegible]4
134	35	40	11.084	43.6	1164	679	1.715	8.511	[illegible]8
135	27	32	5.012	11.6	840	679	1.238	4.545	[illegible]7
136	77	82	4.778	10.7	821	679	1.209	4.382	[illegible]7
137* (2)	55	60	5.730	34.7	374	241	1.553	4.671	[illegible]5
138*	52	57	9.636	(3)	-	241	-	-	
139	42	47	11.084	155	328	241	1.359	9.534	[illegible]0
140	42	47	11.084	155	328	241	1.359	9.534	[illegible]0
141	35	40	11.084	117	434	241	1.800	8.312	[illegible]0
142	27	32	5.012	34	287	241	1.190	4.628	[illegible]23

* Settings wherein each detector was in different-sized hole. Hole diameter (D_h) calculated as explaine[illegible] Table III footnote.

(1) All Bursts through 127 were at essentially atmospheric pressure (apparatus discharged to atmosphere). Bursts 128-136 had 52 psi ambient pressure by restricting discharge.

(2) Bursts 137-142 had 40 psi ambient pressure.

(3) Radioactivity too dispersed for valid time observation.

APPENDIX

TABLE 4

FOURTH SERIES OF TRACER-VELOCITY TESTS
APPARATUS SHOWN ON FIGURE 1c

Burst No.	Detector Depths 1st	Detector Depths 2nd	Hole Dia. Dh, in.	Time, t_o, sec	Flow Rate, bpd Indicated Q_i	Flow Rate, bpd Metered, Q_m	Ratio Q_i/Q_m	Hydr Dia HD, in.	Ratio HD/Dh
147	125	130	4.778	21.4	411	394	1.042	4.689	.981
148	95	100	7.921	52.5	486	394	1.235	7.154	.903
149	72	77	11.084	91	558	394	1.416	9.345	.843
150	55	60	7.921	52.5	486	394	1.235	7.154	.903
151	35	40	5.012	20.5	476	394	1.207	4.598	.917
152	125	130	4.778	6.2	1417	1159	1.223	4.360	.913
153	95	100	7.921	20.4	1252	1159	1.080	7.631	.963
154	87	92	7.921	20.4	1252	1159	1.080	7.631	.963
155*	84	89	9.940	30.3	1342	1159	1.158	9.251	.931
156	82	87	11.084	34.7	1463	1159	1.262	9.886	.892
157	80	85	11.084	37.4	1357	1159	1.171	10.256	.925
158	72	77	11.084	39.2	1295	1159	1.117	10.495	.947
159	67	72	11.084	35.6	1426	1159	1.230	10.011	.903
160*	65	70	10.754	30.7	1555	1159	1.342	9.310	.866
161*	63	68	9.571	23.2	1623	1159	1.400	8.122	.849
162	55	60	7.921	18.5	1380	1159	1.191	7.279	.919
163	35	40	5.012	7.1	1373	1159	1.185	4.637	.925
164*	84	89	9.940	48	847	659	1.286	8.790	.884
165	82	87	11.084	58.8	863	659	1.310	9.707	.876
166	80	85	11.084	62.4	814	659	1.234	9.994	.902
167	72	77	11.084	57.	891	659	1.352	9.560	.863
168	67	72	11.084	62.4	814	659	1.235	9.994	.902
169*	65	70	10.754	47.2	1011	659	1.534	8.718	.811
170*	63	68	9.571	33.	1141	659	1.731	7.329	.766
171	72	77	11.084	62.4	814	659	1.2[illegible]	9.994	.902
172	82	87	11.084	123	413	257	1.607	8.787	.793
173	72	77	11.084	118	430	257	1.673	8.611	.777
174*	65	70	10.754	124	385	257	1.498	8.822	.820

* Settings wherein each detector was in different-sized hole. Hole diameter (D_h) calculated as explained in Table 3 footnote.

TABLE 5

APPENDIX

FINAL SERIES OF TRACER-VELOCITY TESTS
APPARATUS SHOWN ON FIGURE 1d

Burst No.	Detector Depths 1st	2nd	Hole Dia. D_h, in.	Time, t_o, sec	Flow Rate, bpd Indicated Q_i	Metered, Q_m	Ratio Q_i/Q_m	Hydr Dia HD, in.	Ratio HD/D
230*	2	- 3	17.060	6.2	19,572	1304	15.01	4.600	.27[illegible]
231*	1	- 4	19.947	8	20,773	1304	15.93	5.172	.25[illegible]
232*	0	- 5	22.466	8.9	23,710	1304	18.18	5.436	.24[illegible]
233	- 1	- 6	23.625	12.5	18,675	1304	14.32	6.382	.270
234	- 2	- 7	23.625	16.9	13,813	1304	10.59	7.376	.31[illegible]
235	- 4	- 9	23.625	(1)	-	1304	-	-	-
236	- 3	- 8	23.625	23.2	10,062	1304	7.716	8.601	.364
237	- 4	- 9	23.625	(1)	-	1304	-	-	-
238	- 8	-13	23.625	122	1,913	1304	1.467	19.519	.82[illegible]
239	- 3	- 8	23.625	(1)	-	820	-	-	-
240	- 3	- 8	23.625	27.6	8,458	820	10.31	7.471	.31[illegible]
241	- 2	- 7	23.625	20.5	11,387	820	13.89	6.477	.27[illegible]
242	- 1	- 6	23.625	11.6	20,124	820	24.54	4.955	.21[illegible]
243*	1	- 4	19.947	10.7	15,531	820	18.94	4.775	.2[illegible]
244	15	10	4.892	8.9	1,042	820	1.271	4.391	.8[illegible]
245	- 3	- 8	23.625	(1)	-	505	-	-	-
246	- 2	- 7	23.625	23.2	10,062	505	19.92	5.460	.23[illegible]
247	- 1	- 6	23.625	24.1	9,686	505	19.18	5.558	.2[illegible]
248*	1	- 4	19.947	16	10,386	505	20.57	4.598	.23[illegible]
249	15	10	4.892	14.3	648	505	1.283	4.370	.89[illegible]

* Detectors straddled an increase in hole diameter.
(1) RA too dispersed for definitive time observations.

TABLE 6

APPENDIX

COMPARISON OF METHODS FOR PICKING
TRANSIT TIMES IN EJECTIONS UNDER THE
INFLUENCE OF HOLE DIAMETER INCREASES

Burst No.	Ratio of Indicated Flow Rate/Metered Rate: Based on Peak-to-Peak Transit Times	Ratio of Indicated Flow Rate/Metered Rate: Based on Departure Point Transit Time
69	1.348	1.394
72	1.247	1.808
73	1.319	1.825
74	1.171	1.617
75	1.214	1.466
83	1.058	1.327
88	1.254	1.458
109	1.224	1.663
110	1.367	2.628
124	1.142	1.834
125	1.685	2.917
134	1.111	1.715
141	1.092	1.800
169	.991	1.534
174	1.248	1.498
230	10.456	15.01
231	8.912	15.93
232	12.946	18.18
233	9.782	14.32
234	8.365	10.59
236	4.787	7.716
240	8.088	10.31
246	11.032	19.92
247	11.792	19.18
248	16.789	20.57
Mean	4.857	7.128

TABLE 7

APPENDIX

EJECTIONS IMMEDIATELY BELOW A DIAMETER INCREASE

Burst No.	Distance from D_h Increase to Bottom Detector, feet	Small Dia D_h, in	Hydraulic Dia, in	Ratio, HD/D_h	Best-Fit HD/D_h	Empirical HD'	Time t_p, secs	Flow Rate, bpd Q_i'	Q_m	Error $Q_m - Q_i'$	Ratio Q_i'/Q_m
69	6.9	5.012	6.748	1.346	1.610	8.065	26.7	993	686	-307	1.446
70	5.9	5.012	6.748	1.346	1.400	7.017	26.7	744	686	- 58	1.085
71	4.9	5.012	6.072	1.211	1.225	6.140	21.4	702	686	- 16	1.023
72	3.9	5.012	5.567	1.111	1.094	5.483	17.8	664	686	221	.968
73	2.9	5.012	5.155	1.029	1.000	5.012	15.1	646	686	40	.942
74	1.9	5.017	5.010	1.000	0.934	4.681	14.2	592	686	94	.863
75	0.9	5.012	4.725	.943	0.888	4.451	12.5	602	686	84	.878
82	4.9	5.012	6.226	1.242	1.225	6.140	11.6	1295	1334	36	.971
83	0.9	5.012	4.946	.987	0.888	4.451	7.1	1059	1334	275	.794
88	4.9	5.012	6.432	1.283	1.225	6.140	49.8	302	347	45	.870
89	0.9	5.012	4.392	.876	0.888	4.451	23.1	326	347	21	.939
109	5.9	5.012	8.639	1.723	1.400	7.017	22.3	891	1369	478	.651
110	3.9	5.012	6.303	1.258	1.094	5.483	11.6	1019	1369	350	.744
111	1.9	5.012	5.005	.999	0.934	4.681	7.1	1183	1369	186	.864
124	5.9	5.012	8.236	1.643	1.400	7.017	42.7	465	648	183	.718
125	1.9	5.012	4.752	.948	0.934	4.681	13.4	627	648	21	.968
134	5.9	5.012	8.511	1.698	1.400	7.017	43.6	456	679	223	.672
141	5.9	5.012	8.312	1.658	1.400	7.017	117.	170	241	71	.705
160	4.4	7.921	9.310	1.175	1.154	9.141	30.7	1116	1159	43	.963
161	2.4	7.921	8.122	1.025	0.964	7.636	23.2	1021	1159	138	.881
169	4.4	7.921	8.718	1.101	1.154	9.141	47.2	726	659	- 67	1.102
170	2.4	7.921	7.329	.925	0.964	7.636	33.0	717	659	- 58	1.088
17[illegible]	4.4	7.921	8.822	1.114	1.154	9.141	124	276	257	- 19	1.074
230	2.5	4.892	4.600	.940	0.971	4.750	6.2	1399	1304	- 95	1.073
231	3.5	4.892	5.172	1.057	1.052	5.146	8	1290	1304	14	.989
232	4.5	4.892	5.436	1.111	1.166	5.704	8.9	1445	1304	-141	1.108
233	5.5	4.892	6.382	1.305	1.323	6.472	12.5	1343	1304	- 39	1.030
234	6.5	4.892	7.376	1.508	1.521	7.441	16.9	1328	1304	- 24	1.018
236	7.5	4.892	8.601	1.758	1.755	8.585	23.2	1299	1304	5	.996
240	7.5	4.892	7.471	1.527	1.755	8.585	27.6	1092	820	-272	1.332
241	6.5	4.892	6.477	1.324	1.521	7.441	20.5	1095	820	-275	1.335
242	5.5	4.892	4.955	1.013	1.323	6.472	11.6	1447	820	-627	1.765
243	3.5	4.892	4.775	.976	1.052	5.146	10.7	964	820	-144	1.176
246	6.5	4.892	5.460	1.116	1.521	7.441	23.2	967	505	-462	1.915
247	5.5	4.892	5.558	1.136	1.323	6.472	24.1	696	505	-191	1.378
248	3.5	4.892	4.598	.940	1.052	5.146	16	645	505	-140	1.277

TABLE 8

TRACER-VELOCITY SHOTS CONDUCTED TO EVALUATE PROFILING TECHNIQUES BUT USEFUL IN DETERMINING INFLUENCE OF HOLE DIAMETER, APPARATUS SHOWN IN FIGURE 1c

Burst No.	Detector Depths 1st	Detector Depths 2nd	Hole Dia. Dh, in.	Time, t_o, sec	Flow Rate, bpd Indicated Q_i	Flow Rate, bpd Metered, Q_m	Ratio Q_i/Q_m	Hydr Dia HD, in.	Ratio HD/Dh
179	95	100	7.921	102	250	166	1.506	6.499	.820
180	87	92	7.921	110	232	166	1.398	6.738	.851
182	79	84	11.084	171	297	166	1.789	8.339	.752
183	72	77	11.084	178	285	166	1.717	8.503	.767
184	55	60	7.921	100.6	254	166	1.530	6.456	.815
185	38	43	5.012	20.4	478	404	1.183	4.640	.926
186	42.5	47.5	5.012	20.4	478	404	1.183	4.640	.926
188	43.5	48.5	5.012	18.7	521	404	1.290	4.460	.890
191	125	130	4.778	26.7	329	259	1.270	4.286	.897
192	110	115	4.778	26.7	329	259	1.270	4.286	.897
193	97	102	7.921	74.5	343	259	1.324	6.919	.874
194	90	95	7.921	73.9	346	259	1.336	6.892	.870
195	80	85	11.084	98	518	421	1.230	10.010	.903
196	75	80	11.084	89	570	421	1.354	9.549	.862
197	55	60	7.921	46.3	552	421	1.311	6.953	.878
198	35	40	5.012	19.6	497	421	1.181	4.643	.926
202	125	130	4.778	25.8	341	281	1.214	4.378	.916
203	108	113	4.778	23.1	380	281	1.352	4.166	.872
204	97	102	7.921	47	543	442	1.229	7.169	.905
205	90	95	7.921	45.5	561	442	1.269	7.058	.891
206	80	85	11.084	94	540	442	1.222	10.045	.906
207	59	64	7.921	53.5	477	442	1.079	7.631	.963
208	42	47	5.012	13.3	733	668	1.097	4.802	.958
209	38	43	5.012	12.5	780	668	1.168	4.668	.931
210	52	57	7.921	49	521	442	1.179	7.314	.923
220	95	100	7.921	104	246	164	1.500	6.522	.823
221	90	95	7.921	110	232	164	1.415	6.699	.846
222	80	85	11.084	106	479	340	1.409	9.369	.845
223	75	80	11.084	104	488	340	1.435	9.282	.837
224	68	73	11.084	102	498	340	1.465	9.194	.829
225	59	64	7.921	54.4	469	340	1.379	6.780	.856
226	52	57	7.921	63.3	403	340	1.185	7.292	.921
227	42	47	5.012	13.3	733	569	1.288	4.464	.891
228	35	40	5.012	13.3	733	569	1.288	4.464	.891

TABLE 9 APPENDIX

PREPRINT--SUBJECT TO CORRECTION

Paper No. 906-15-J

For release: March 21, 1970

PRACTICAL FIELD INTERPRETATION OF TEMPERATURE SURVEYS

by

Billy P. Morris
WACO Inc.
Midland, Texas

--oOo--

For presentation at the
Spring Meeting of the Southwestern District
Division of Production
Inn of the Golden West, Odessa, Texas
March 18-20, 1970

--oOo--

(The statements and opinions expressed herein are those of the author and should not be construed as an official action or opinion of the Institute.)

--oOo--

Division of Production
American Petroleum Institute
Dallas, Texas

9

PRACTICAL FIELD INTERPRETATION OF TEMPERATURE SURVEYS

Billy P. Morris, WACO Inc., Midland, Texas

ABSTRACT

Temperature logs have been used as an evaluation tool since the early 1930's. The simplicity of operation and expression of data once led the industry to believe that formation reaction and data interpretation could be stereotyped.

Attempts at quantitative analysis of the collected data revealed that temperature information collected in the borehole is the end result of one of the most complicated energy transfer systems encountered in downhole survey operations. Efforts to reconcile these myriad variations have resulted in many interpretive techniques making useful field interpretation of temperature data highly controversial and subject to a high degree of error if misapplied.

Some basic characteristics are reflected in each and every temperature curve, and if properly analyzed, can serve as a useful qualitative tool for evaluation of current downhole conditions.

INTRODUCTION

Downhole temperature surveys have long enjoyed immunity from the more exacting and precise evaluation methods that are applied to other types of well bore surveys. They have retained much of their popularity by virtue of the simplicity of the physical operation and unsophisticated presentation of data. One merely lowers a "thermometer on a string" in the well, takes readings at various depths, and records the results as a graph of temperature (fahrenheit or centegrade) vs. depth.

Conditions are usually assumed stable and fairly constant, and the temperatures recorded in the well bore are inferred to be the conditions extending for some distance into the formation.

All modifying or contingent conditions must be applied by the interpreter, and every man becomes an "expert" after seeing one or two temperature logs.

Temperature logs have been used for all types of investigation; i.e., cement top location, production analysis, casing and tubing leaks, frac evaluation, injection zone definition, and even attempts to locate unevaluated oil bearing sands behind the casing.

The "cook-book" style of interpretation used until recent years produced some successful evaluations and many dismal failures, and overextension of temperature log capabilities has caused misapplication of technique.

Promotional efforts to the contrary, temperature tools of excellent quality are available to the entire industry through several suppliers.

The validity of the information derived depends more upon the application and interpretive technique used than the tools themselves.

A basic understanding of these tools and their capabilities is necessary to properly apply the data they collect.

TOOLS

The downhole recording tools fall into three classifications: (Figure 1).

1. Absolute or normal temperature: A single element tool calibrated and aligned to detect the existing temperature downhole and transmit this information to the surface, where it is recorded as actual temperature versus depth.

   This tool measures the temperature of the borehole fluids at a single point and is subject to the total of the vertical as well as lateral

effects of temperature transition zone. Sharp definition of temperature interfaces is improbable unless the differential is extreme, and slight changes often go unnoticed unless recording sensitivity is high. Total transition from one temperature to another is usually averaged over a long vertical interval.

2. Temperature Differential: The differential tool utilizes two elements physically separated by a given distance. Both elements detect the absolute temperature of the fluids at their respective depths. These temperatures are impressed upon a "comparison circuit" and the difference between them is transmitted to the surface and recorded. Hence, if one element detects 76 degrees and the other, five feet above it, registers 75 degrees, a 1 degree progression for the interval is recorded. As long as this progression remains the same as the tool is moved downhole, no further deflection is recorded, but should the rate of change increase to 2 degrees per five feet interval (i.e. top element 78 degrees and bottom 80 degrees) an additional one degree deflection would appear on the recording for the given interval.

   The two element tool can be calibrated and used as a "true differential" indicator by taking stationary readings. The actual difference in temperature would be determined by the deflection. During most logging operations, the progress downhole is usually continuous; therefore, both the rate and the amount of temperature change affect the readings, and the log is used as a relative temperature change indicator. The actual temperature is recorded simultaneously on a separate circuit. The advantage in this usage is a more prominent indication of temperature change over a given interval.

3. A-Priori "Differential": This principle simulates the differential effect by using a single element and an electronic "memory circuit". The single element detects the temperature of the well fluids and sends this information to a memory cell or delay circuit. After a pre-selected time this temperature impulse is fed back into a "comparison circuit" and is impressed with the impulse currently generated by the temperature element. The difference in temperature detected at the two time-intervals is recorded as differential.

   This tool is not a true differential indicator with respect to depth since it depends upon movement for its depth spacing. Theoretically, the spacing is controlled by logging speed, but in actual practice, the time delay for feed back in milliseconds and normal logging speeds are not compatible. No consistent spacing control is possible without electronic "gateing" keyed to the depth meter. Continuous movement again incurs effect from both the rate and amount of temperature change, and confines the use of this curve to an instantaneous slope change indicator. As with the other differential tools, the actual temperature is recorded on a separate circuit. The downhole tool used in the A-priori method is only the normal

or absolute temperature sonde. All the delay circuits are in the surface instrumentation.

The only basic data collected by the temperature sonde is the absolute temperature inside the well bore and the depth at which it is recorded.

The interpretation of temperature data does not depend upon the downhole temperature that exists, but rather, the degree and rate of change under controlled conditions. An examination of the conditions involved will lay the groundwork for more accurate interpretation.

The normal gradient exists because of a temperature equilibrium process from the interior of the earth (warmer) to the surface (cooler). Heat flow is vertical and forms a gradient or constantly decreasing temperature as it approaches the surface. The existence of a hole in the ground does not change the gradient appreciably (Figure 2-A).

Should the temperature be changed by pumping cooler or warmer fluids downhole, a differential is formed between the well bore and the formation temperature at any given depth and a lateral or horizontal "gradient" is formed between the well bore and the formation (Figure 2-B). A process of equilibrium is set up, and heat flows from the warmer source to the cooler point. The coolest point in the system is the terminal point for this equilibrium process and, therefore, is the last point to be affected by the heat flow.

The well bore is either the source or terminal point of these heat exchanges, and any temperature change must be considered the result of the sequence of heat flow rather than the instantaneous condition of the reservoir outside the well bore.

Fluid moving inside the well bore not only affects the zone accepting the fluid, but the formation temperature is changed outside the entire extent of the hole by conduction (Figure 3). This change is constantly expanded to some distance until the formation will conduct only the amount of heat that is being carried away (or added) by the moving fluids. "Steady state" heat flow then exists, and unless the temperature of the fluid moving in the well is changed, there will be no additional change in formation temperature immediately around the well bore with continued fluid movement. When the fluid movement is stopped, the temperatures in and around the well bore attempt to recover to normal gradient for each depth. The rate of recovery inside the well bore (data collection point) depends not only upon the zones that have or have not accepted the fluid, but also upon the ability of each of the formations to transmit heat to or from the well bore. The formations not only transmit heat directly back to the well, (Figure 4-A), but as one formation warms or cools faster than the adjacent one, local equilibrium effects are set up in the formation which slows the rate of recovery in some zones and speeds that of others, causing a distortion

of the lateral temperature transfer characteristics of these formations (Figure 4-B).

The mechanical arrangement of the well also affects the rate of heat transfer at each depth by increasing or decreasing conductive properties (Figure 5).

Temperature tools have no "Radius of investigation" into the formation and can only measure the temperature inside the well bore. Recorded temperatures at any one given time do not detect the many small changes in the formation that affect the final well bore temperatures.

A "single run" temperature log run and interpreted only by the "cooler or hotter" technique can result in completely erroneous information.

One simple rule of thumb can be applied to "on the spot" interpretations which will greatly increase the accuracy of field analysis of temperature logs:

> Static well bore fluids always assume the temperature of the "Dominant Temperature field" immediately adjacent to the well bore.

This obvious over simplification of conditions can be made applicable if the sequence of events that result in a particular "Dominant field" are examined.

When cooler fluids move thru the well and into the formation "boundary cooling" is caused around the hole and above and below the zone taking fluid. Heat flows back to the well bore from some radius away from the well. Heat at gradient temperature for each depth is available for recovery except in the zones accepting fluid (Figure 6). The heat source across the zone of injection is approximately the same as the well bore fluid temperature, therefore, little or no heat is available to warm the well fluids opposite these zones. There is no warming trend after shut in and this area lags behind in its rate of recovery. The Dominant Temperature Field in the non-injection zone is at normal gradient for that depth, but the Dominant field of the injection zone is approximately the fluid temperature under injection conditions. A trend to positive slope develops over the non-injection interval but no slope trend (either positive or negative) is developed through the zone of injection (Figure 7).

These ideal conditions are relatively easy to identify since they consider only the temperature fields and unobstructed path of heat flow.

Changing well bore mechanics change both the radius of dominant field and the heat replacement rate. The temperature curve will reflect the presence of tubing, casing, enlarged hole, squeezed zones or any other

change from continuous borehole configuration by a deflection from its established slope or trend.

The following examples are reproductions of temperature decay curves run at varying times after shut in. The total pattern of progression identifies the zones readily, but any single curve of each series might well be misinterpreted if analyzed with no other information available.

Figure 8 - The effect of tubing in continuous cased hole - Deflection of temperature towards the injection temperature (cooler) at the base of tubing string.

Figure 9 - Tubing, casing and open hole - Temperature deflections at each change of hole configuration.

Figure 10 - Tubing set to total depth. Note changing direction of deflection at base of tubing with time as one dominant temperature field (annular) space is replaced by secondary field.

Figure 11 - The effects of enlarged hole in non-injection zone. Additional volume of hole distorts otherwise normal progression of temperature after shut in and causes cool anomaly on log.

Figure 12 - Enlarged hole between two injection zones. Boundary cooling above and below combines with increased hole volume (non-injection zone) to cause coolest anomaly in non-injection zone.

These examples point up the possible error to be incurred by indiscriminate interpretation of "cold" spots as zone of injection. Study of the family of curves shows, however, that the established proportional rate of recovery developed in the non-injection zones is retarded in the injection zones by the extended dominant field of nearly constant temperature, and <u>rate</u> of <u>change</u> becomes the factor for interpretation.

Selection of intervals of lateral fluid movement must then be made on a basis of zone temperature stability rather than actual temperature at any given time. To detect this "stability", it is necessary to observe a family of curves recording the <u>sequence</u> of temperature progression after some controlled action.

Many field operations do not allow time for this accumulation of data. Interpretation must be made with inferred temperature sequence based on data collected during a shorter time interval, and augmented or modified by the interpretors knowledge of the physical changes that have been caused by some surface initiated action.

Prior information; i.e., established normal gradient for local area, well bore mechanics, surface temperature of injected or produced fluids, compressible or non-compressible fluids, measured injection or production rates, type of fluids (reacting or stable) etc., must be considered

when assuming sequence of temperature change.

Base logs should be run to establish existing temperature conditions downhole for comparison to subsequent temperatures.

When a large differential (20° F or more) exists between moving well fluids and normal downhole temperatures, or prior temperature logs under the same conditions are available, base logs may sometimes be dispensed with, although interpretation is greatly facilitated by their use. Remember, prior injection zones, squeeze cementing, liner applications, etc., may have generated a dominant formation temperature downhole other than normal gradient.

> Figure 13 - Well "B" has been prepared for recompletion in a lower zone by squeezing the upper zone and opening a new zone by perforating.

Lower zone is treated with acid to stimulate production. Examination of the after treatment log shows heating anomalies exceeding the normal gradient in both the new zone and the squeezed zone. Assumed condition; the original zone broke down or acid treatment channelled up to the old producing interval. Comparison with the base log shows that the upper heating anomaly is the result of the cement squeeze and existed before treatment. Since there has been no change in the upper heating indication the conclusion is that the squeeze held and the lower zone treated properly.

In the absence of base log or prior information, it is imperative to make at least two or three temperature traverses over the interval after an initiated change to observe the relative sequence and amount of change incurred by the action. Injection wells normally involve only one induced change (injection to shut in) and the temperature progression is from one stabilized condition towards another. Care must be exercised in gathering prior information, however, lest some change in injection rates or pressures change downhole conditions and generate new and confusing temperature fields.

> Figure 14 - This established low rate injection well was subjected to step-rate test which ultimately broke out below the logged depth. The well was then placed back on injection at the previous low rate, allowed to stabilize, and logged with decay series temperature survey. The lower zone and bottom of the hole had been cooled below normal injection temperature by the step-rate tests, but the current injection curve shows no injection past bottom of the hole. Study of this sequence shows positive (warming) trend above 2550 feet, stable temperature at current injection temperature over interval 2550-2600 feet and negative progression below 2600 feet. The dominant temperature fields are three phase, cooler on the bottom with very slight injection at normal rates. Warmer above, no injection,

and constant at current injection temperatures through the center (maximum current injection).

This analysis could not have been positive without prior information but a base run under injection and a shut in curve after 4-6 hours would have identified the stable zone as 2550-2600 feet where no gradient, either positive or negative, was generated. The constant temperature then indicates the major injection zone.

TREATMENT AND PUMP IN ANALYSIS

Intermittent injection or pumping operations never generate "steady state" heat transfer conditions. These operations are usually very short term, and the temperature changes induced by them are subsequently shorter lived. Since the conditions are in a constant state of fluxuation, they are often changed again, before they recover completely. Relative anomalies are obliterated by additional action from the surface before another temperature traverse is made over the interval. Interpretation is made by comparison of the temperature curves, and identification of the more nearly stable zones in relation to the sequence of events.

The same dominant temperature field principles still apply but are sometimes more difficult to identify. When scanning the log for zones of injection, consider the temperature anomaly that should be generated by the last action taken and identify the partially stablized zone in relation to the prior traverse.

A base log of existing temperatures before pumping is an absolute necessity to properly locate the affected interval in recompletions and old producers.

Figure 15 - Examine well "Y". Open hole completion, tubing set to point "D" and producing from zone "B". Tubing is pulled and well readied for retreatment to stimulate additional zones.

A light single stage frac is pumped away and a frac analysis temperature log is run:

Run No. 1 - Compared to known normal gradient shows cooling from casing seat to point "D" with some cooler points opposite all three major zones. Apparently the well has accepted treatment in all three zones.

Run No. 2 - Progression of temperature opposite zone "A" indicates no treatment into "A". Zone "B" is accepting treatment in top and bottom of zone and zone "C" apparently well treated. (Note stable temperatures at bottom.)

Base Log - Comparison of base log over zone "C" shows that stable anomaly in the lower section of "C" was residual from the effects

of producing period and only the very top portion of "C" accepted treatment. The dominant temperature fields are identified in sequence: Base Log, run No. 1, run No. 2, and have indicated the need for further treatment or a change of treating procedures.

Figure 16 - A base log and run No. 2 will provide enough interpretive data if the characteristics of the more nearly stable zones are recognized. Interpret for the zones that indicate no slope either positive or negative and recognize that any slope, either negative or positive, indicates a transient temperature exchange.

TREATING FLUIDS

Acids or reacting treating fluids generate heat when they contact the formation. These reactions must be allowed for in the interpretation of treatment evaluation temperature curves.

The sequence of operation should again be considered and the step by step analysis applied. Treating with cooler fluids first cools the formation by contact, but the heat of reaction warms the zones accepting treatment. This produces a two phase temperature reaction.

The temperature of the treating fluids should be adjusted to maintain all the reactions either positive or negative with respect to normal downhole temperature.

For example: Cool acid is pumped downhole and arrives in place 14 degrees cooler than the normal temperature. The formation is cooled 14 degrees by contact but the heat of reaction in the formation generates a 14 degree temperature rise in the zone accepting treatment. The resulting well bore temperature would be the same as the normal temperature and no anomaly would exist. The curve would have no positive interpretive value (Figure 17-A). Should the acid treatment have arrived downhole at -20 degrees to the normal temperature, the zone accepting treatment would also show deflection from the normal temperature indicating that it had been exposed to the treating fluids. Normal progression of the temperature recovery would then indicate a dominant temperature field in the treated zone while the untreated zones recover at a higher rate (Figure 17-B).

Displacement and overflush fluids should be brought to the same surface temperature as the treating fluids to avoid altering the temperature indications caused by treatment.

Interpretation should always be made from the absolute temperature curve rather than from the so-called "differential" curve. The T or differential curve is <u>not</u> a measurement of temperature, but an indication of slope change. Due to boundary cooling and/or heating, the slope of an absolute curve starts to change at some distance above the actual zone

of injections and the practice of identifying the zones from the differential curve alone can lead to complete misinterpretation of the results (Figure 18).

The use of the Delta curve should be confined to identifying the slope changes of the absolute curves as they enter the zones of "stability". Slight increases in the rate of slope change from transient to "stable" temperature conditions may be more closely defined with respect to depth and the actual zone of fluid acceptance identified more specifically.

Fluid movement in the well bore during the time the temperature traverse is being made destroys all evidence of the anomalies being formed in the formation. The well bore temperatures are constantly being displaced by the moving fluids, and no temperature other than that of the fluid stream is detected. Wells on vacuum, counter-flow, or backflow conditions show only the temperature of the fluid and the vertical extent of its travel as long as the fluid continues to move.

The Dominant Temperature field principle can be used to increase the accuracy of "on the spot" field interpretations if the heat flow characteristics in the formation are related to the resulting data collected in the well bore.

RULES FOR APPLICATION

1. Determine well bore arrangement.

2. Review prior data or logs, if possible, to determine variations from normal temperatures.

3. Run base temperature or establish a constant for comparison from prior data before any action is taken to alter downhole temperatures.

4. Consider the sequence of action with respect to the temperature progression.

5. Interpret any slope (negative or positive) as an area of transient temperature and identify "stable" zones by their approach towards vertical gradient. (No slope) These are the zones of near constant temperature over their entire vertical extent.

CONCLUSIONS

Temperature logs are a valid qualitative field interpretation tool when properly executed and interpreted.

"Single Run" temperature logs without modifying data or prior logging history can easily be misinterpreted.

Interpretation technique must utilize rate and sequence of temperature progression rather than "cooler or warmer" principle.

"Dominant Temperature Field" principle applies to all temperature log analysis and must be considered for consistently accurate interpretation.

"Differential" or Delta-T curves should be used only to more closely define slope changes in the absolute curve, and <u>must</u> <u>not</u> be construed as temperature readings.

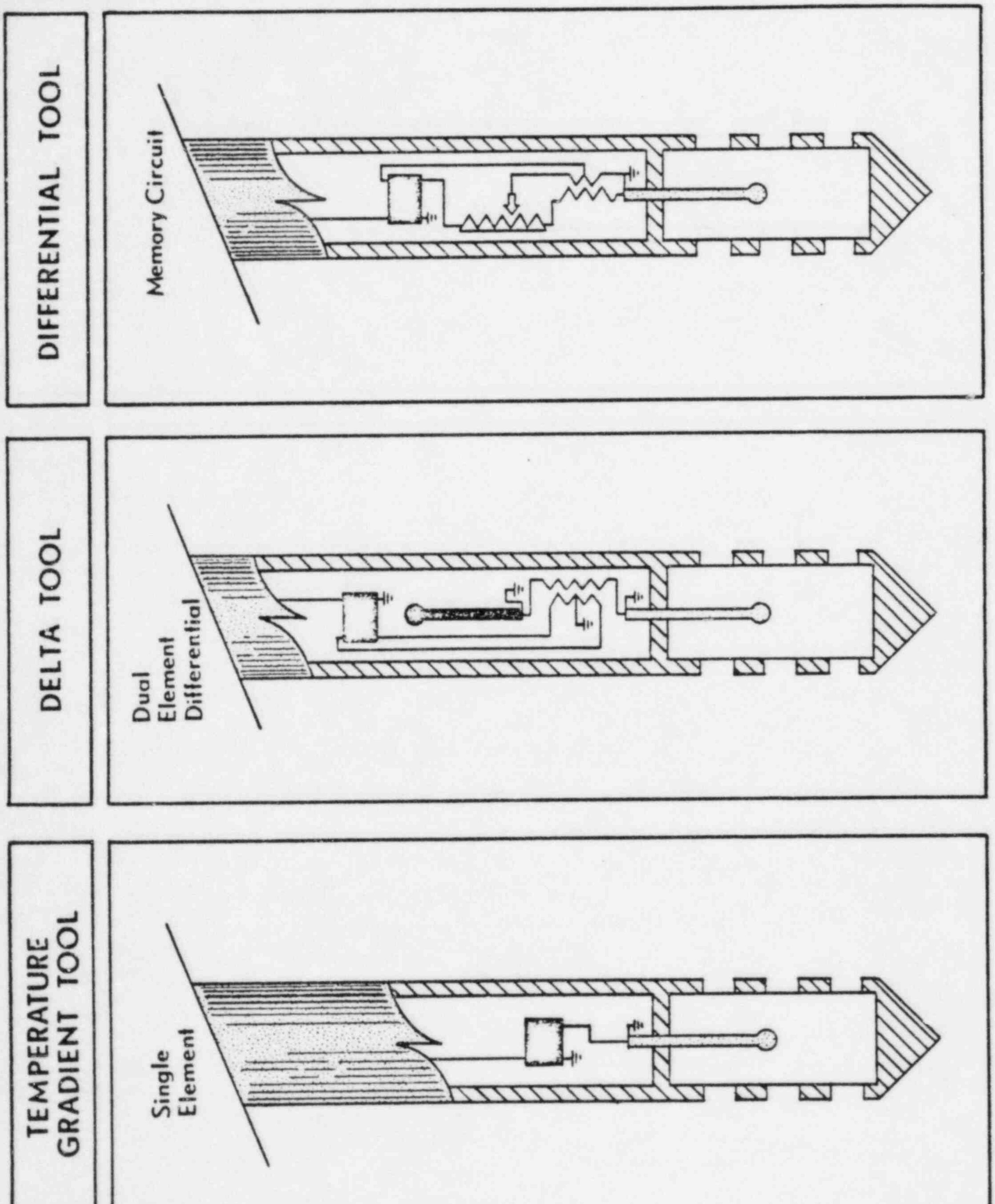

TEMPERATURE GRADIENT TOOL
Single Element
DELTA TOOL
Dual Element Differential
DIFFERENTIAL TOOL
Memory Circuit

FIG. 1

VERTICAL GRADIENT

LATERAL GRADIENT
(INJECTION)

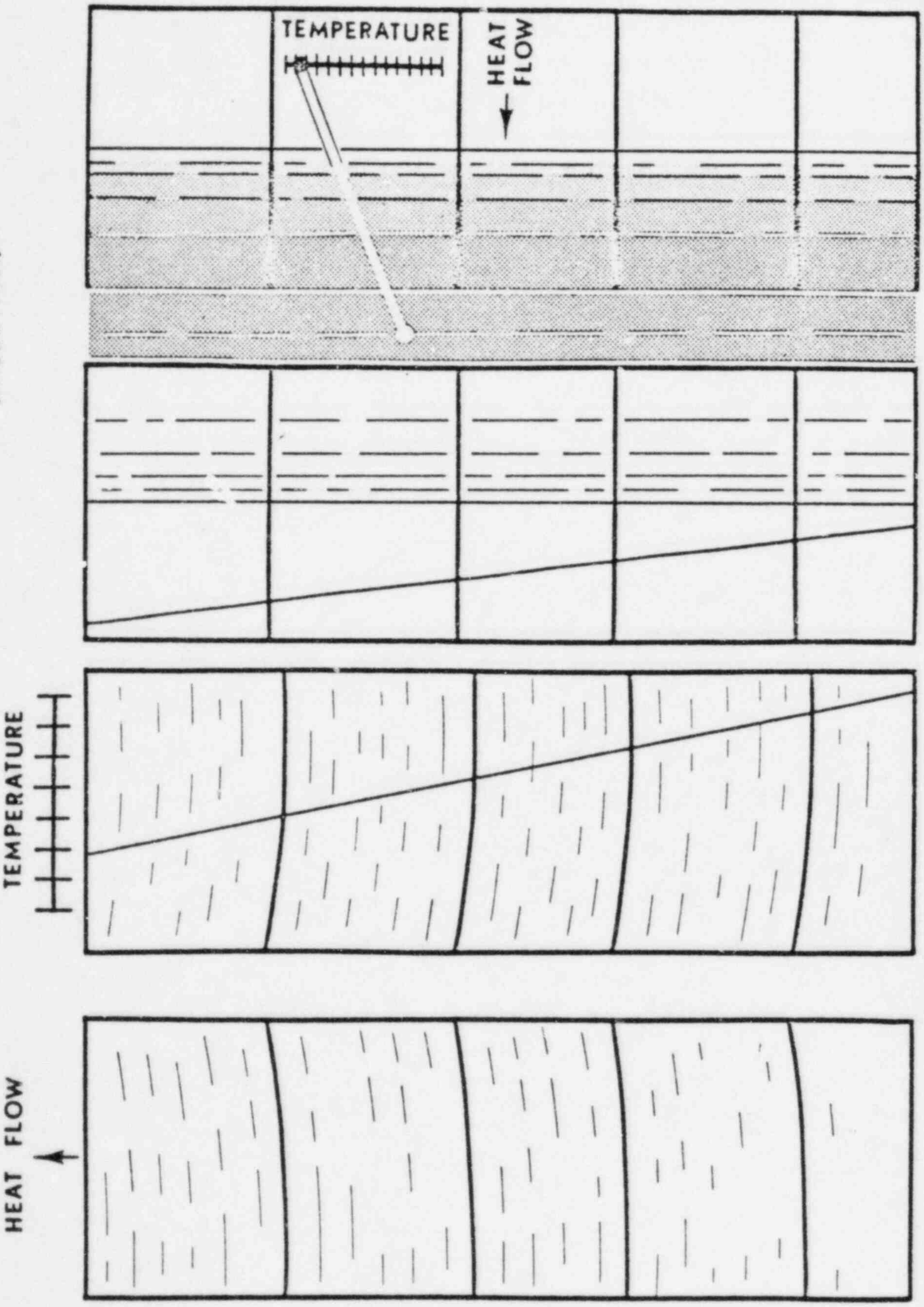


FIG. 2A

FIG. 2B

VERTICAL AND LATERAL EFFECTS

STABILIZED INJECTION TEMPERATURES

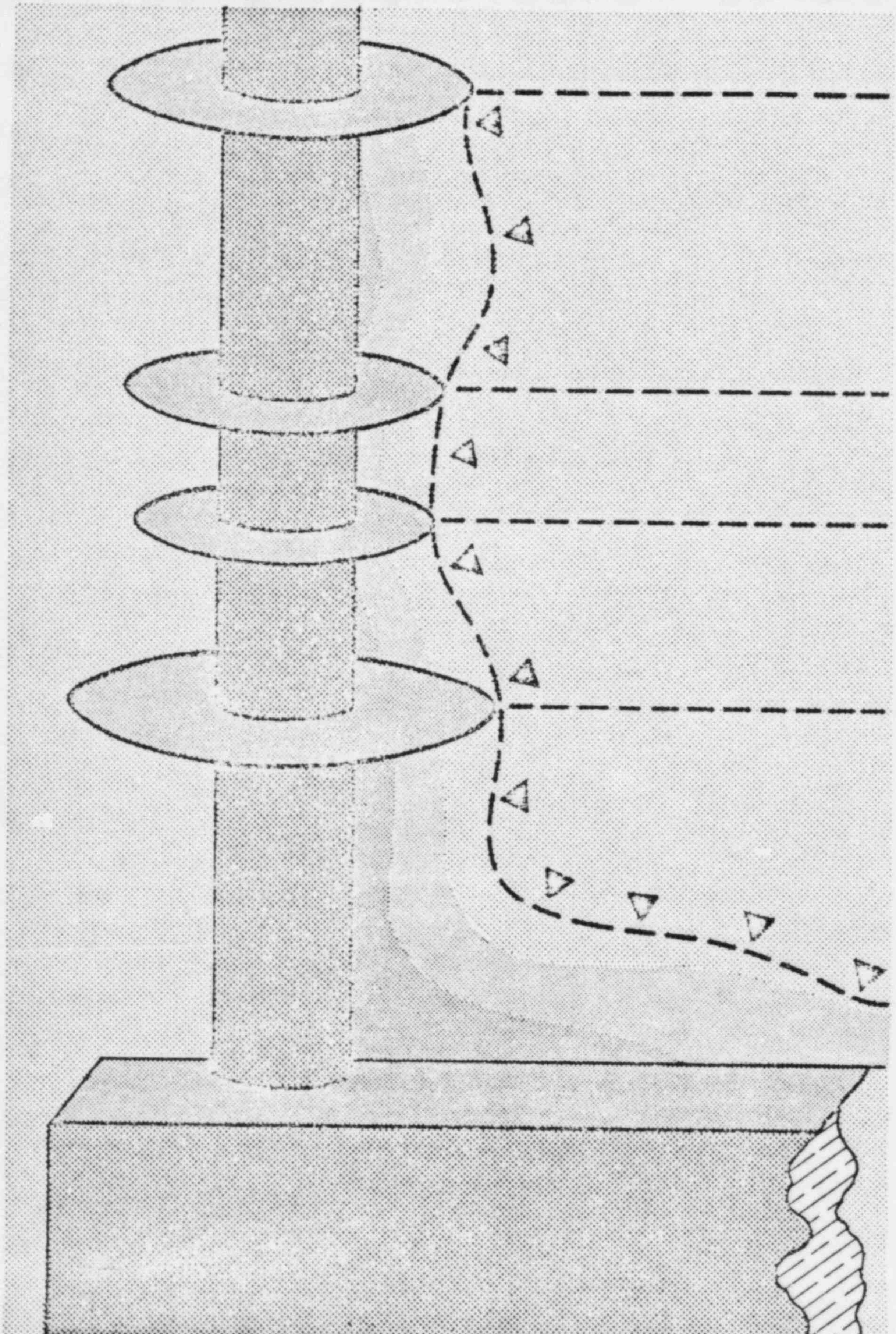


FIG. 3

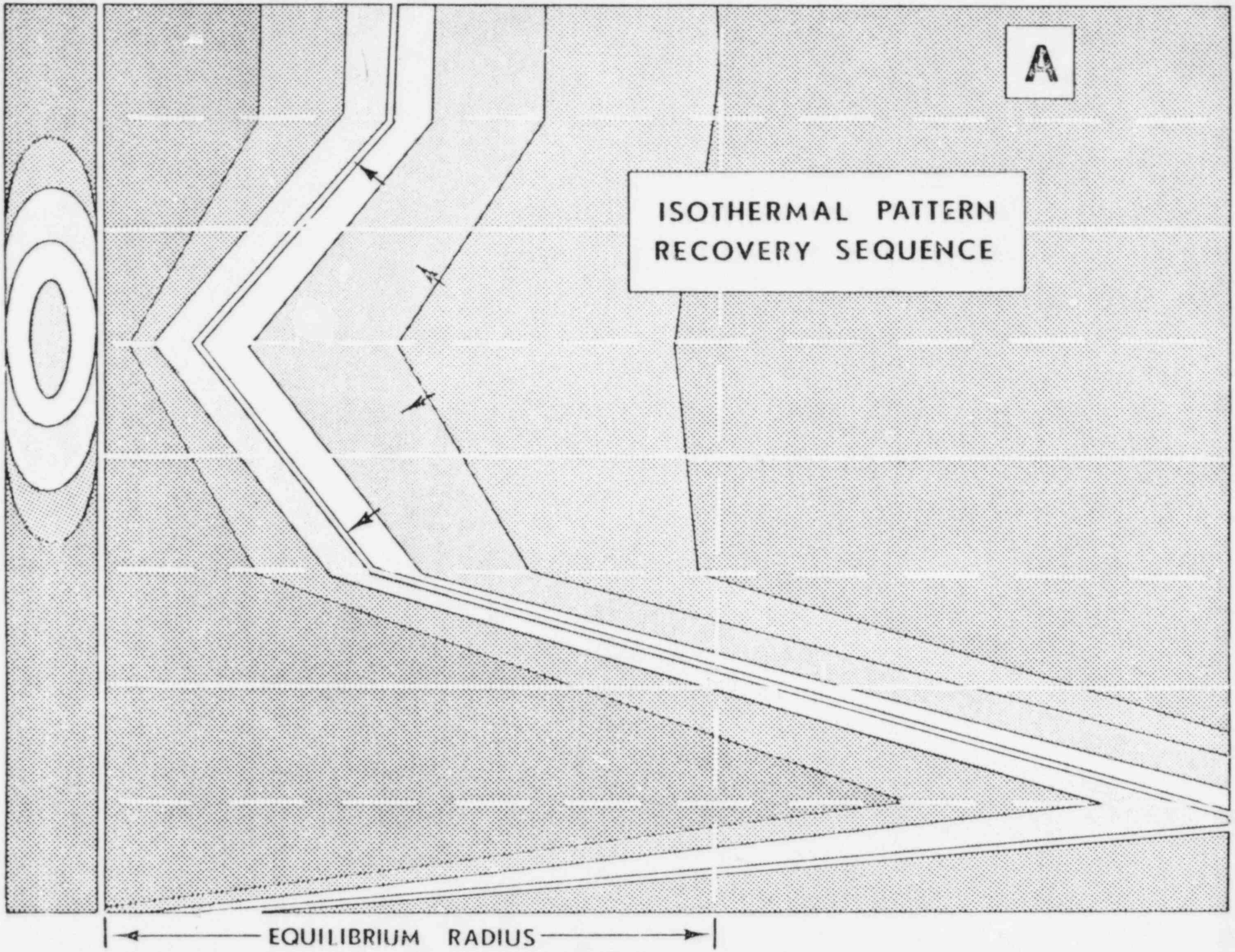
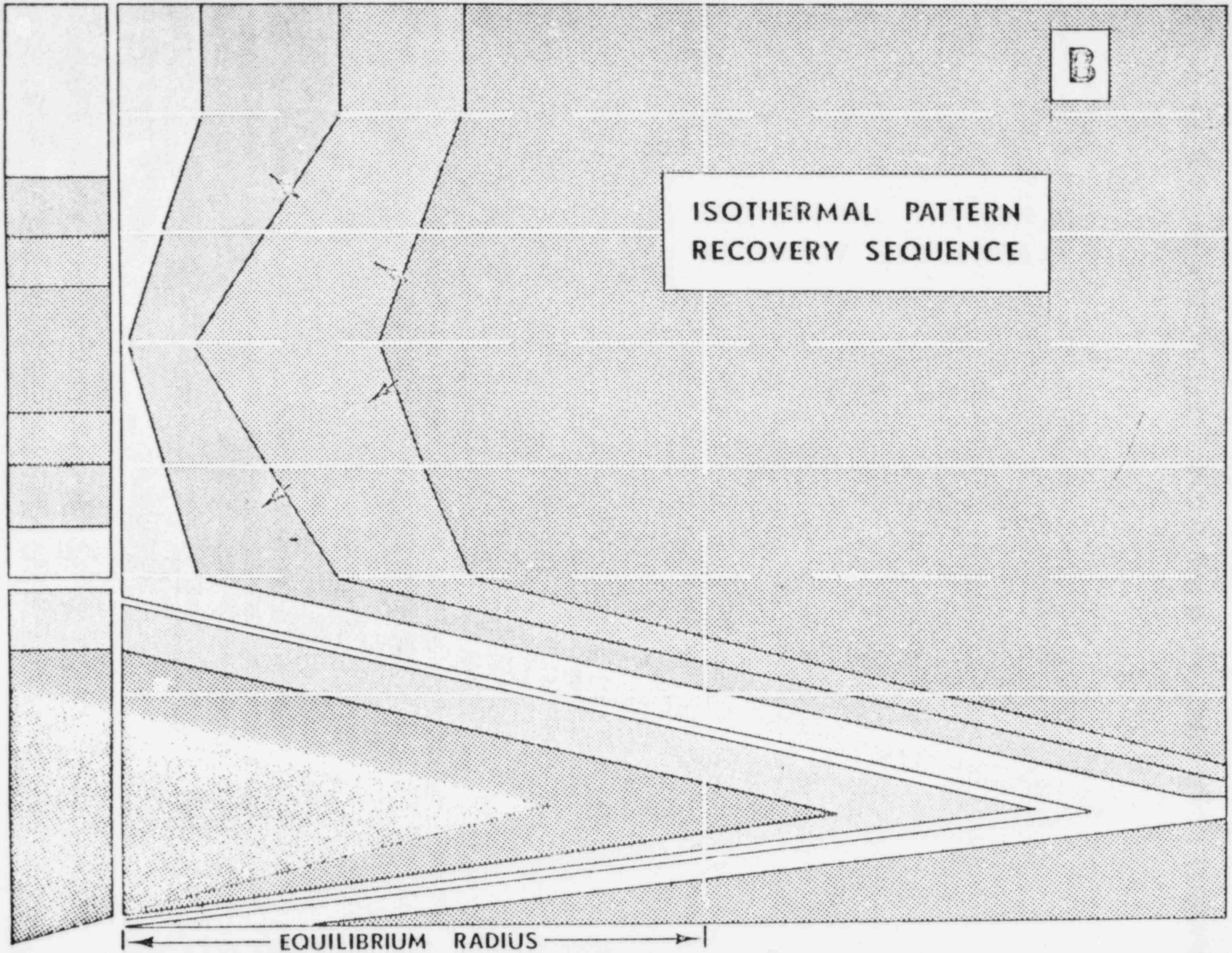

A
ISOTHERMAL PATTERN
RECOVERY SEQUENCE
EQUILIBRIUM RADIUS

FIG. 4 A


B
ISOTHERMAL PATTERN
RECOVERY SEQUENCE
EQUILIBRIUM RADIUS

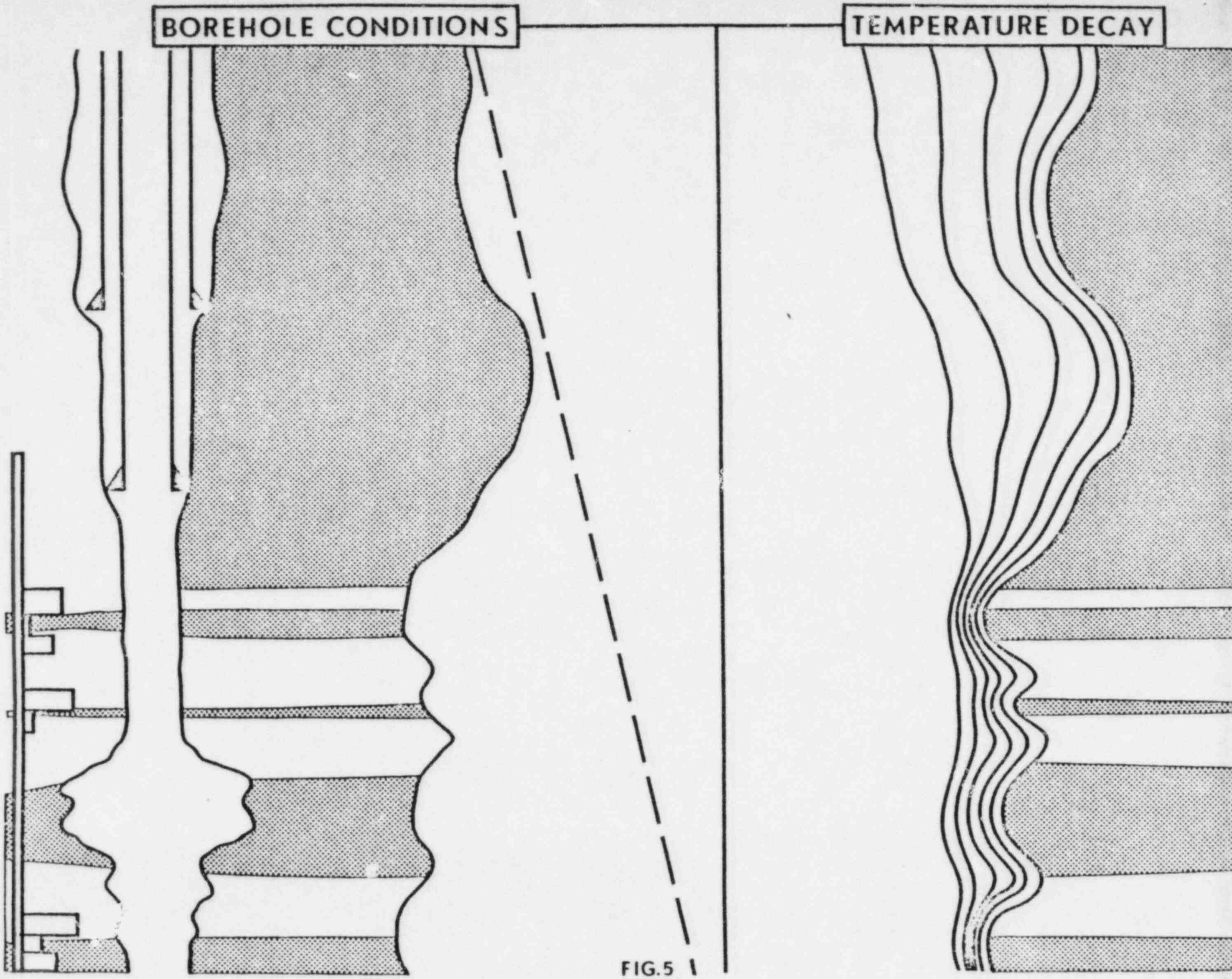


FIG.5

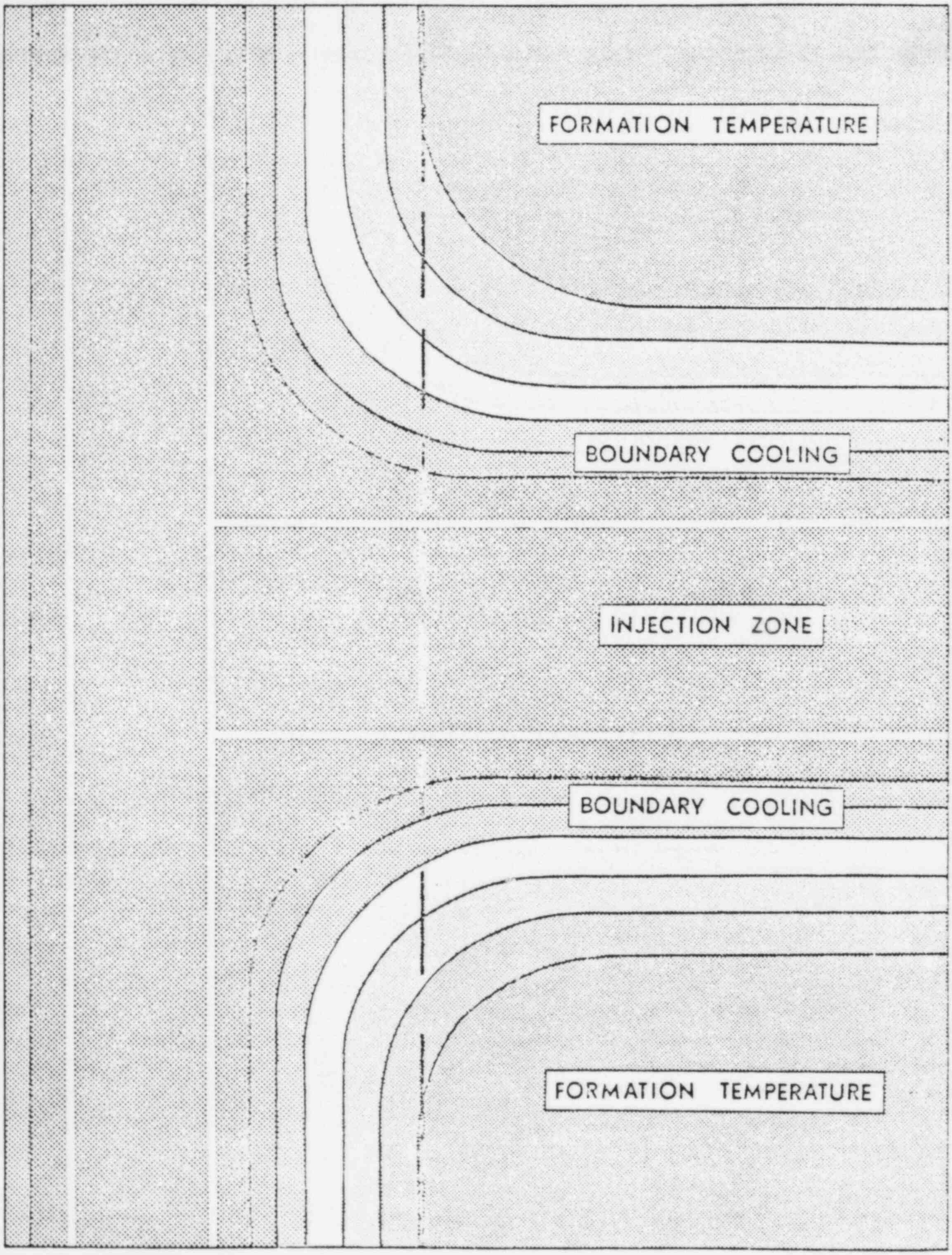

FORMATION TEMPERATURE
BOUNDARY COOLING
INJECTION ZONE
BOUNDARY COOLING
FORMATION TEMPERATURE

FIG. 6

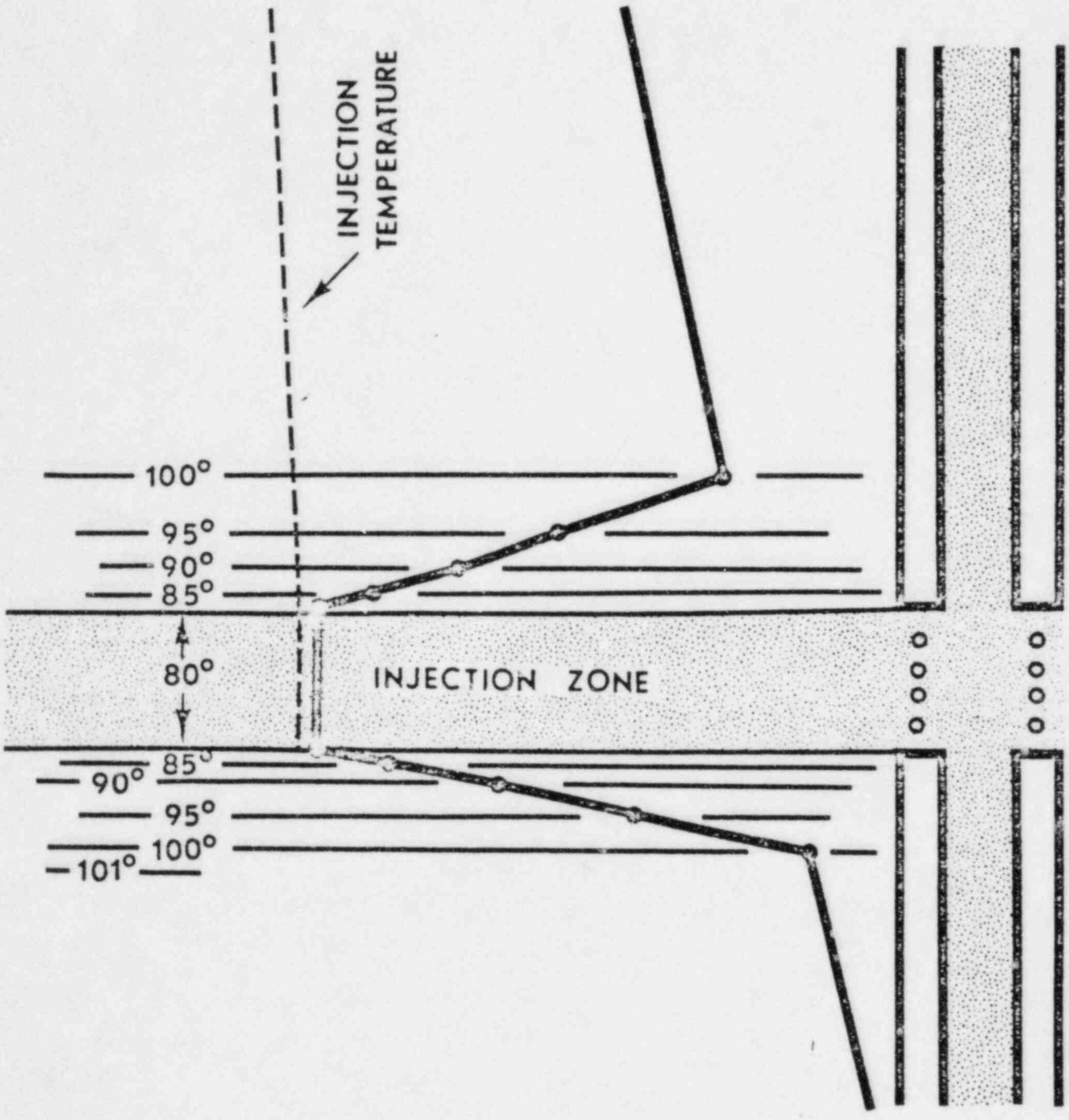
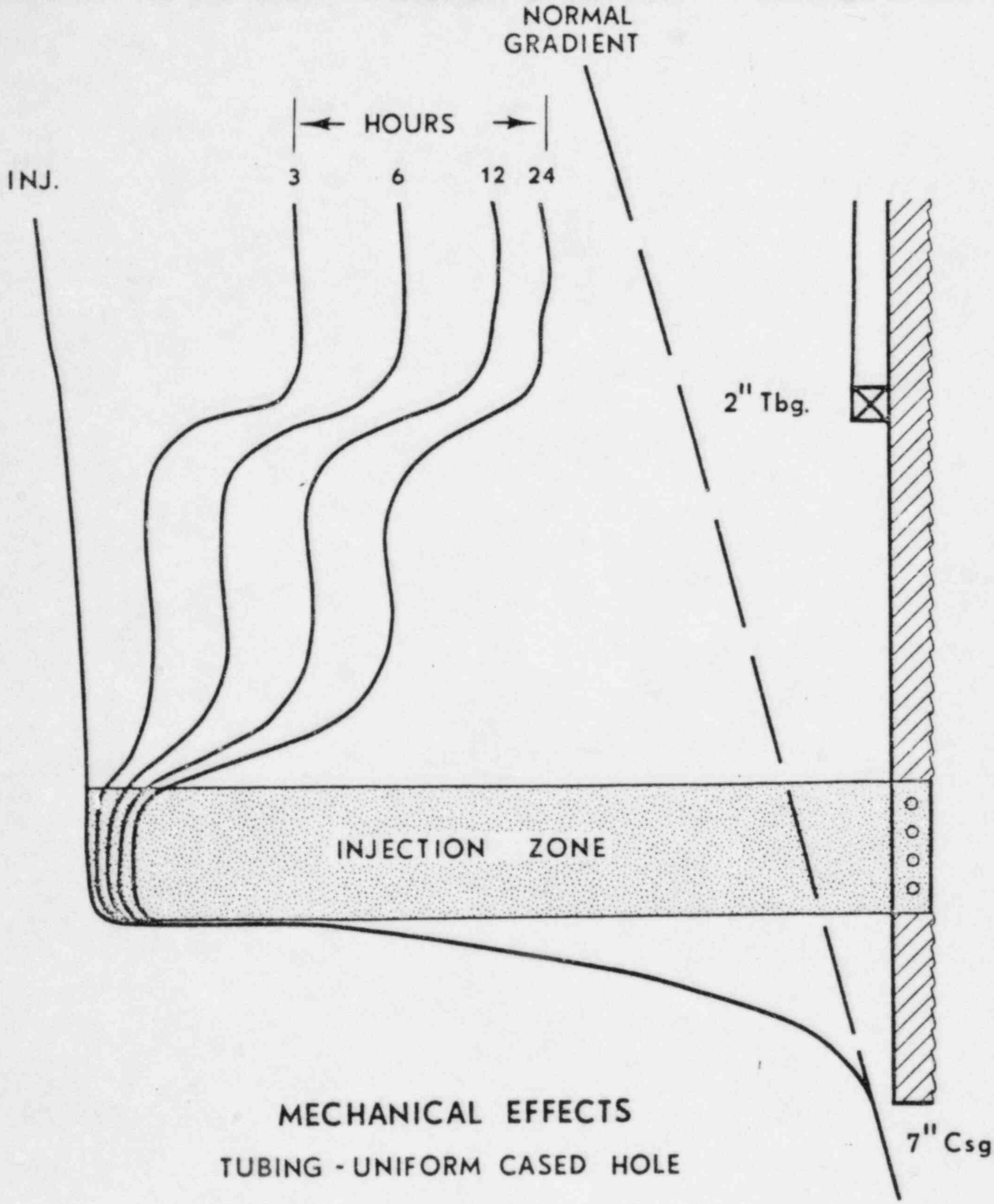

INJECTION TEMPERATURE
100°
95°
90°
85°
80°
INJECTION ZONE
85°
90°
95°
100°
101°

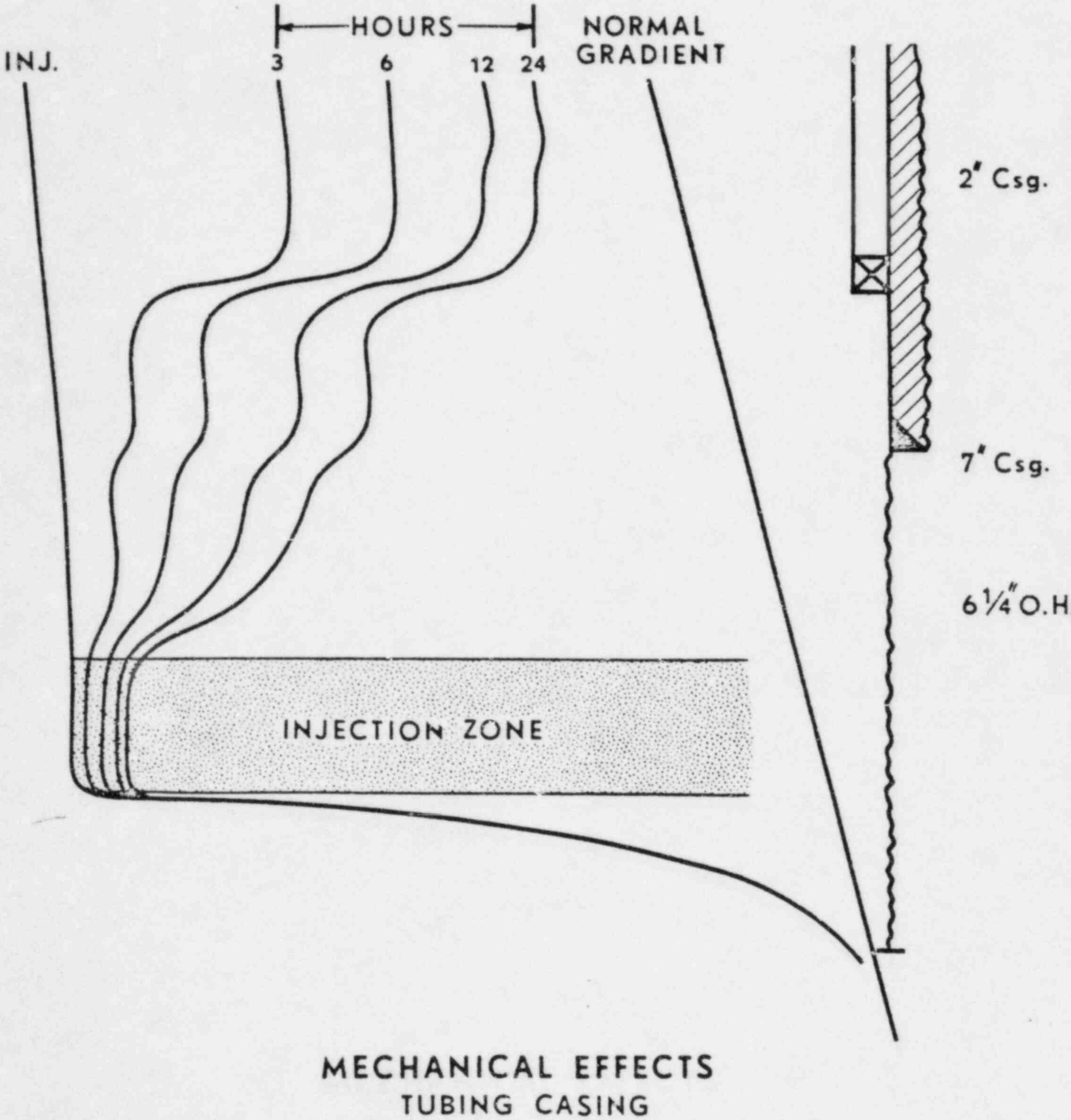
FIG. 7



MECHANICAL EFFECTS

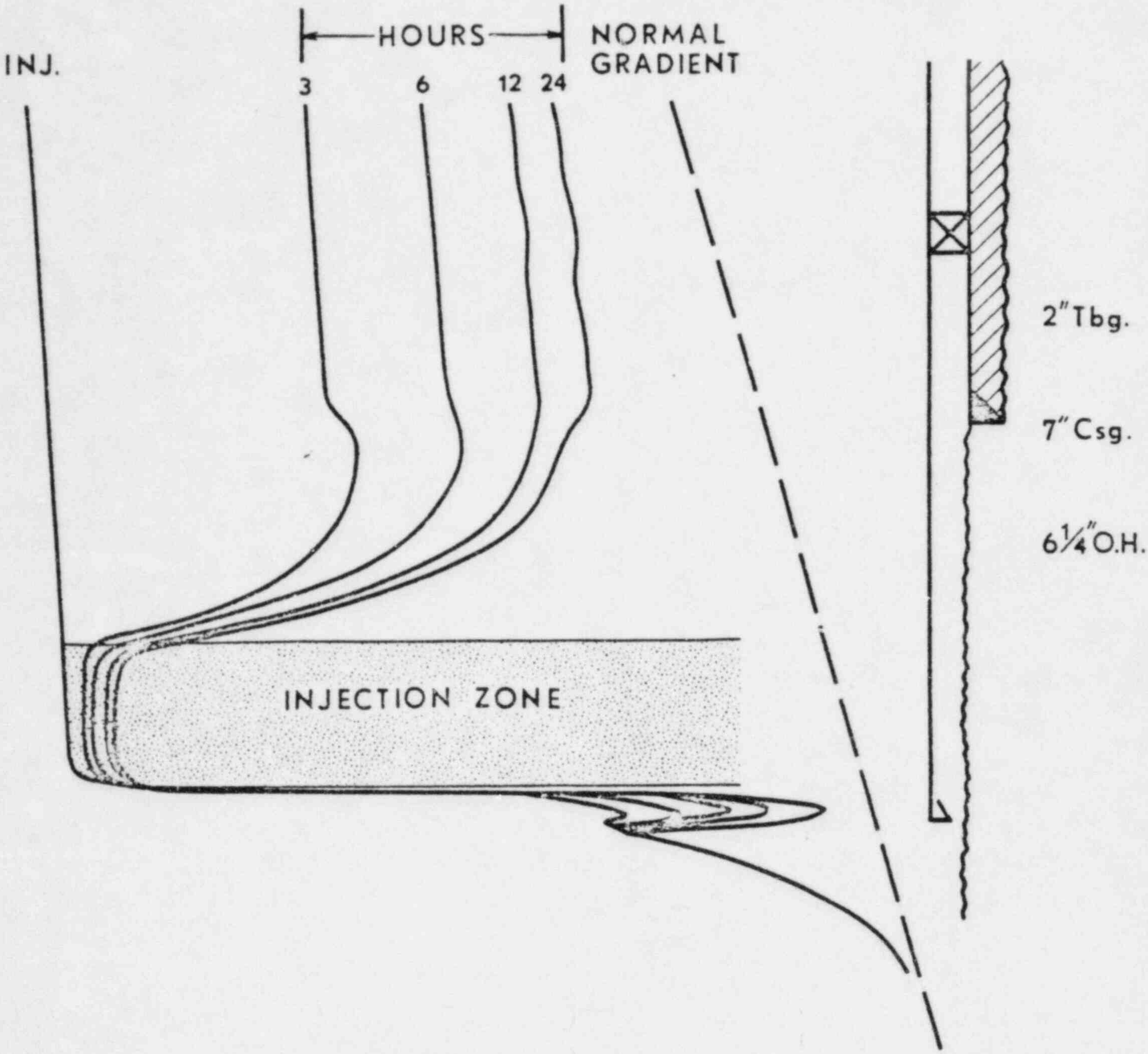
TUBING - UNIFORM CASED HOLE

FIG. 8



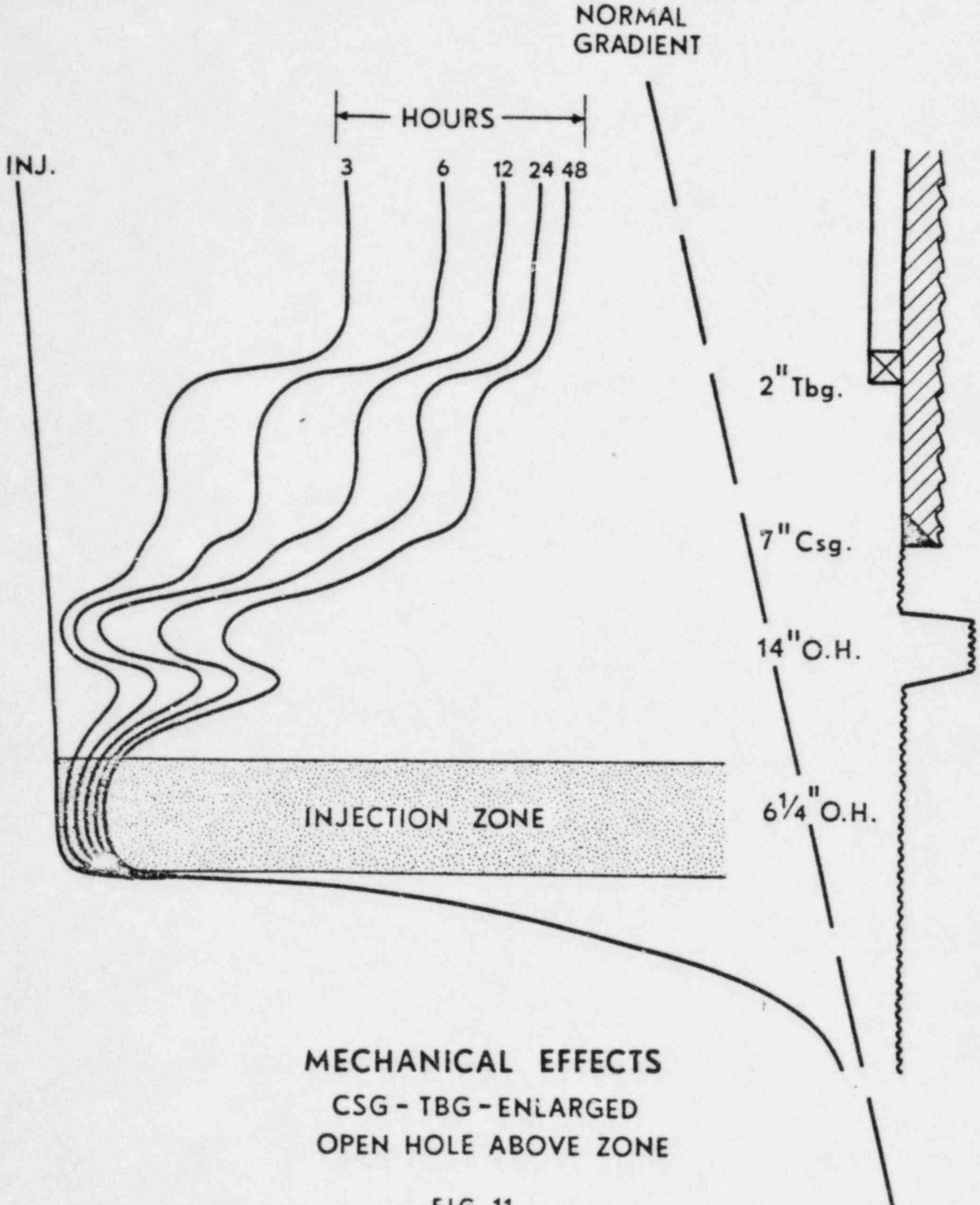
MECHANICAL EFFECTS
TUBING CASING
UNIFORM OPEN HOLE

FIG. 9



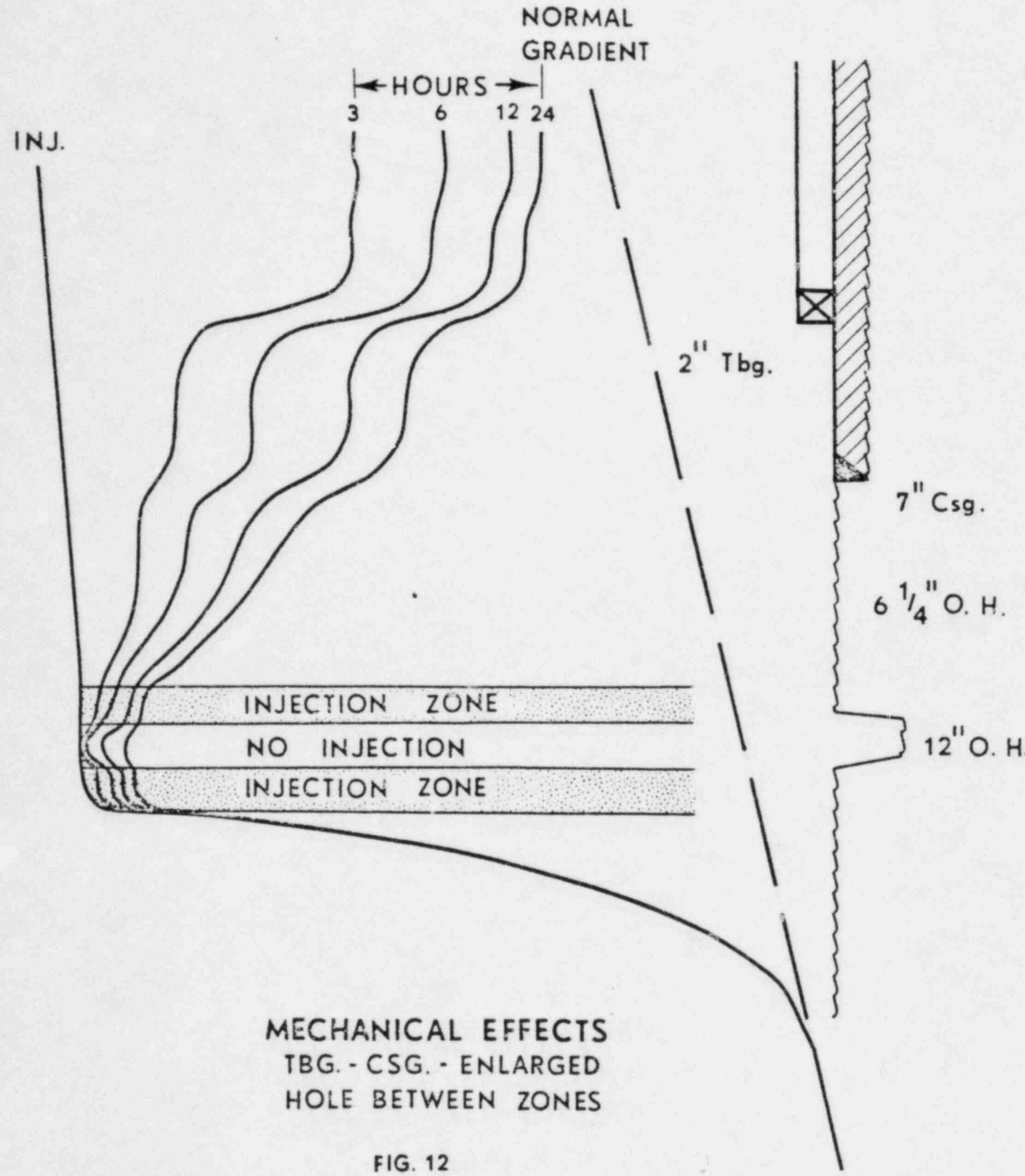
MECHANICAL EFFECTS
CSG – UNIFORM OPEN HOLE
TUBING SET TO BOTTOM

FIG. 10



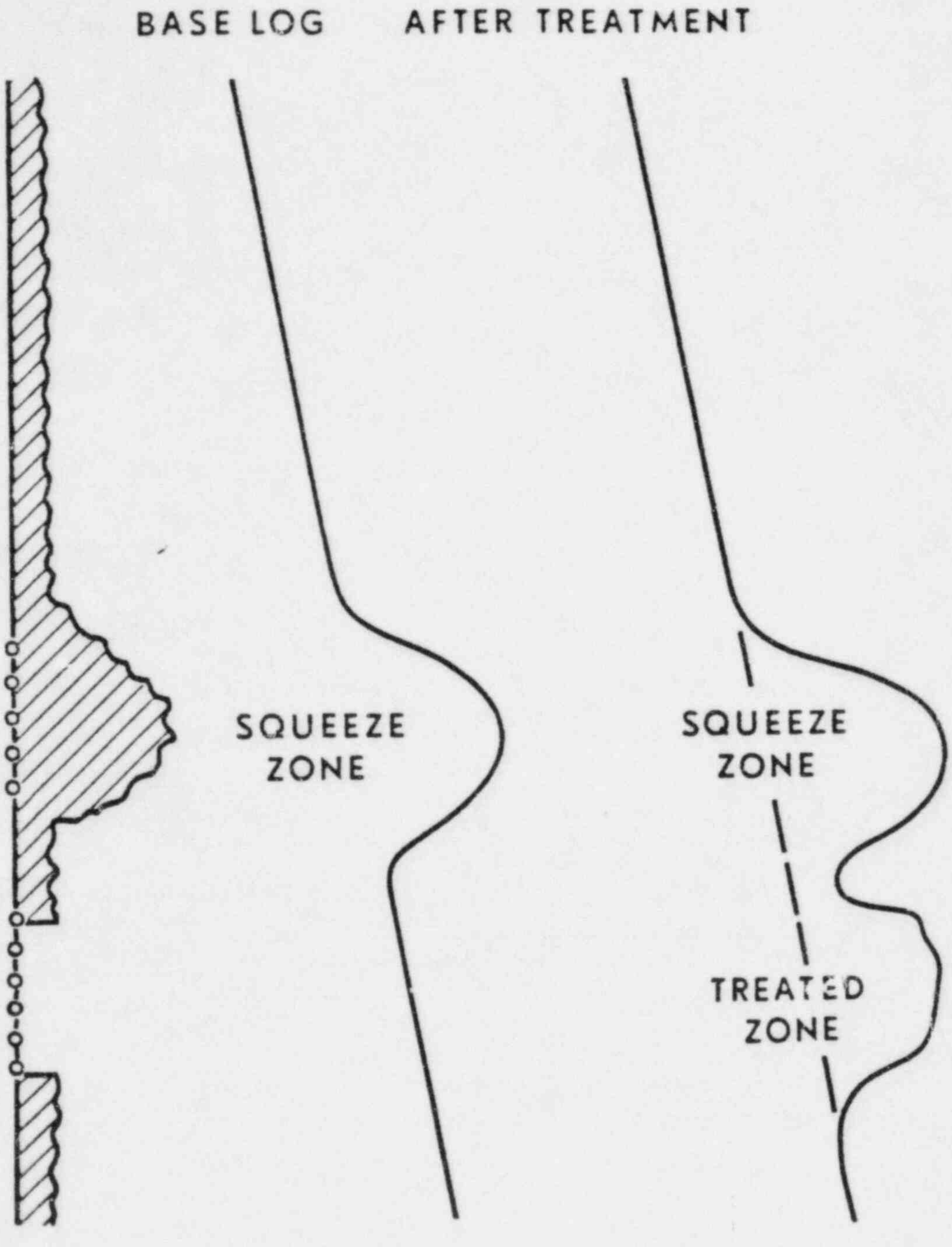
MECHANICAL EFFECTS
CSG - TBG - ENLARGED
OPEN HOLE ABOVE ZONE

FIG. 11



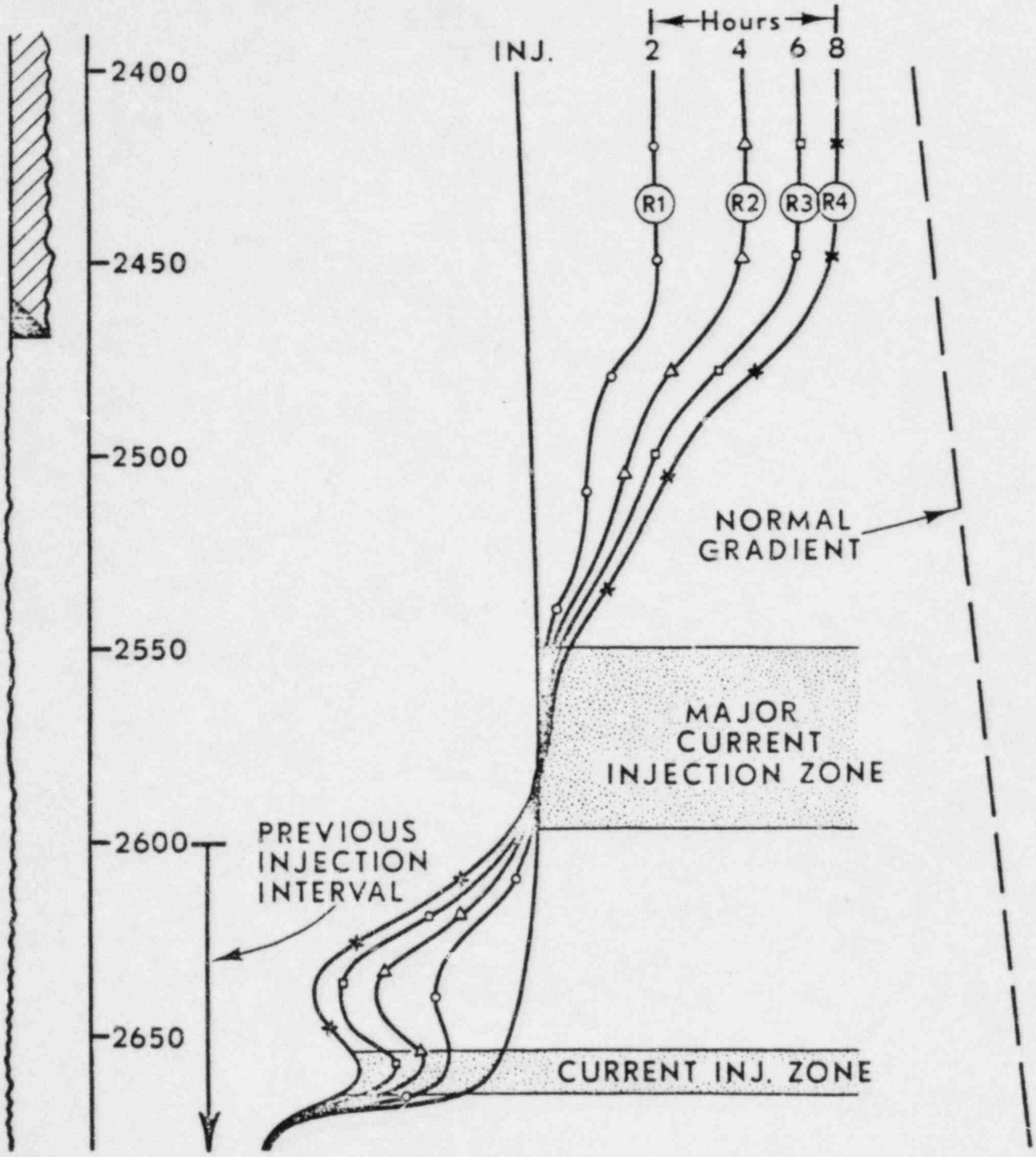
MECHANICAL EFFECTS
TBG. - CSG. - ENLARGED
HOLE BETWEEN ZONES

FIG. 12



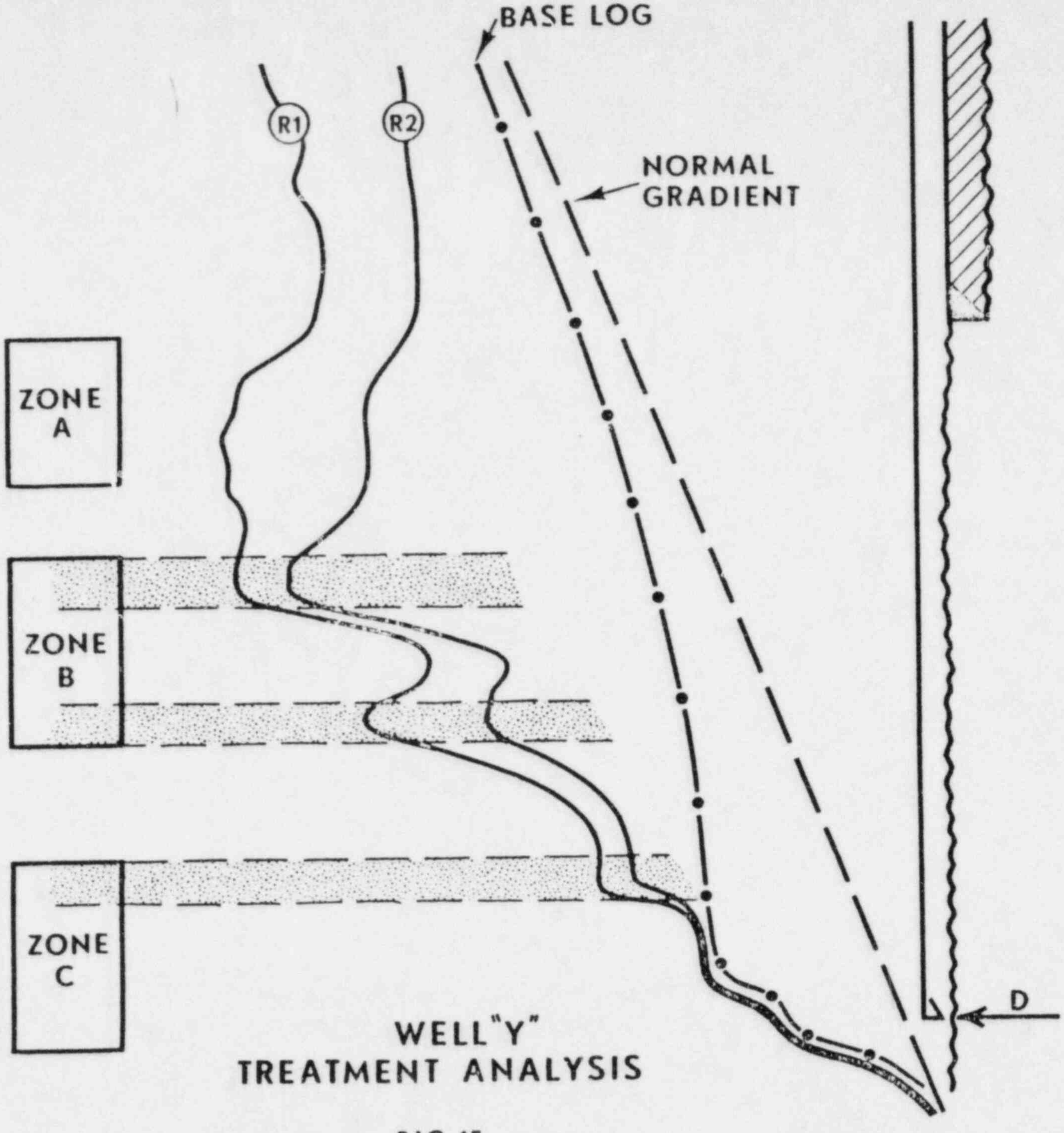
WELL "B"
BASE CURVE COMPARISON

FIG. 13



3 PHASE TEMPERATURE
INFLUENCE

FIG. 14



WELL "Y"
TREATMENT ANALYSIS

FIG. 15

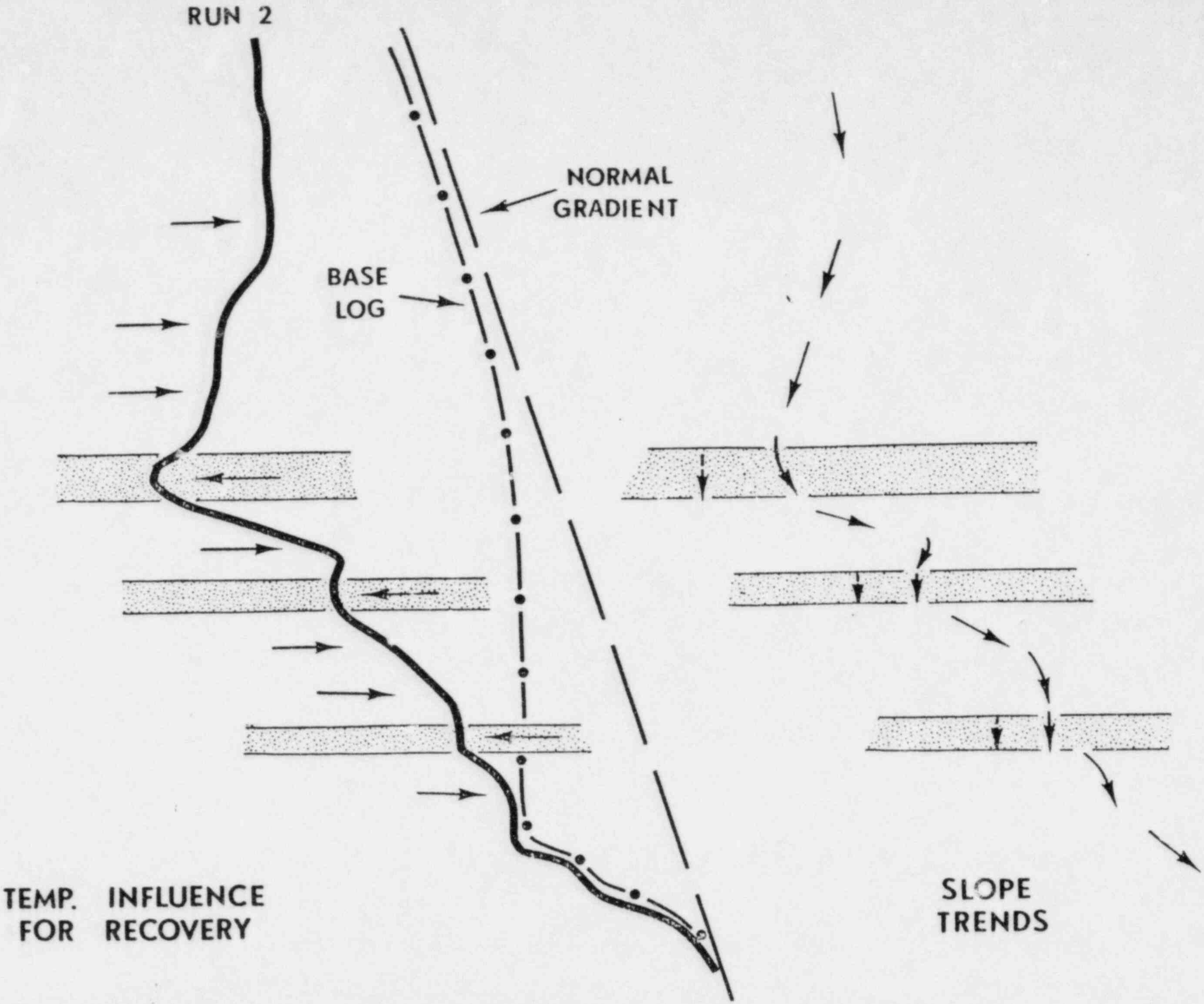

RUN 2
NORMAL GRADIENT
BASE LOG
TEMP. INFLUENCE FOR RECOVERY
SLOPE TRENDS

FIG. 16

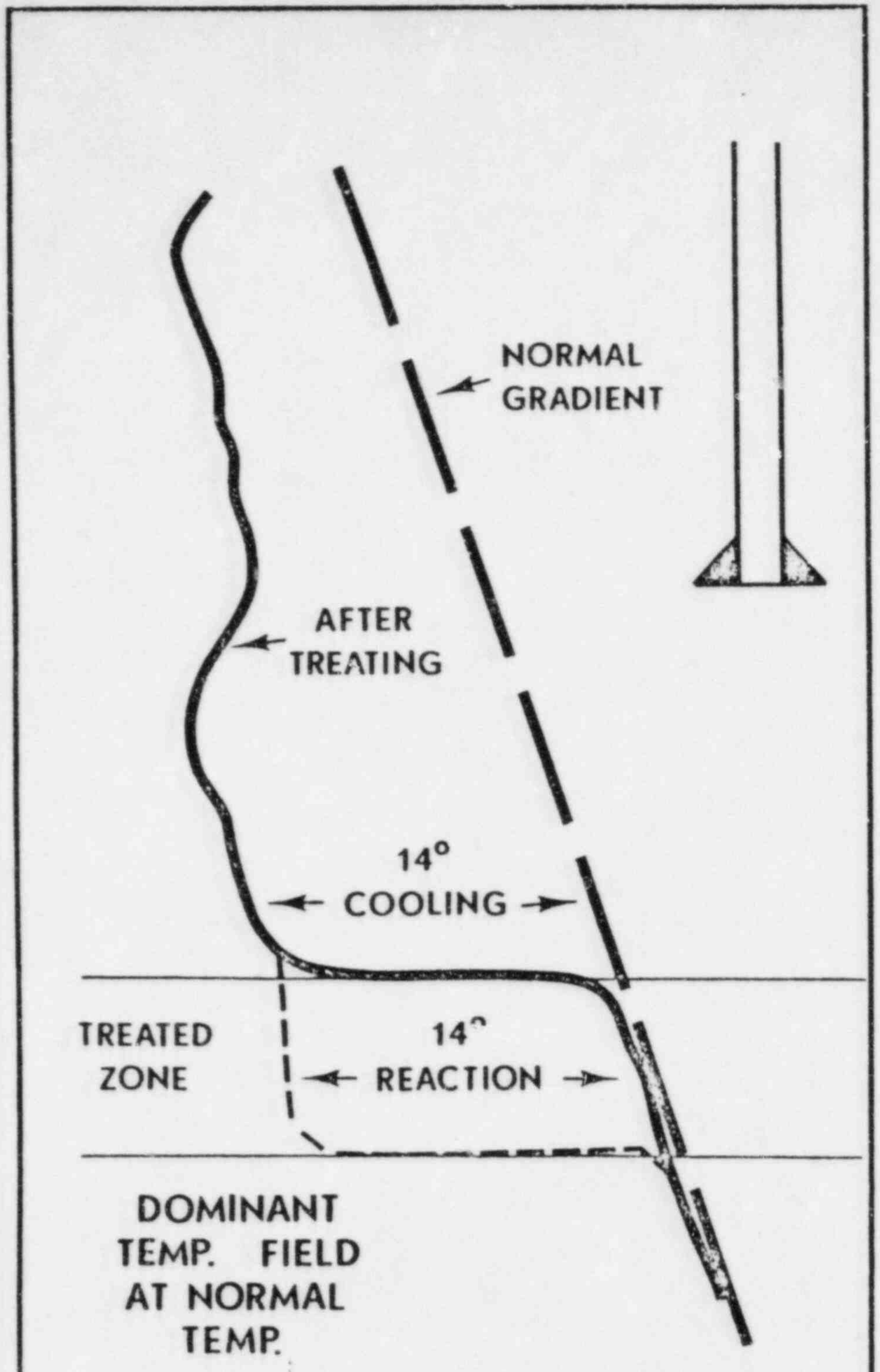


FIG. 17-A

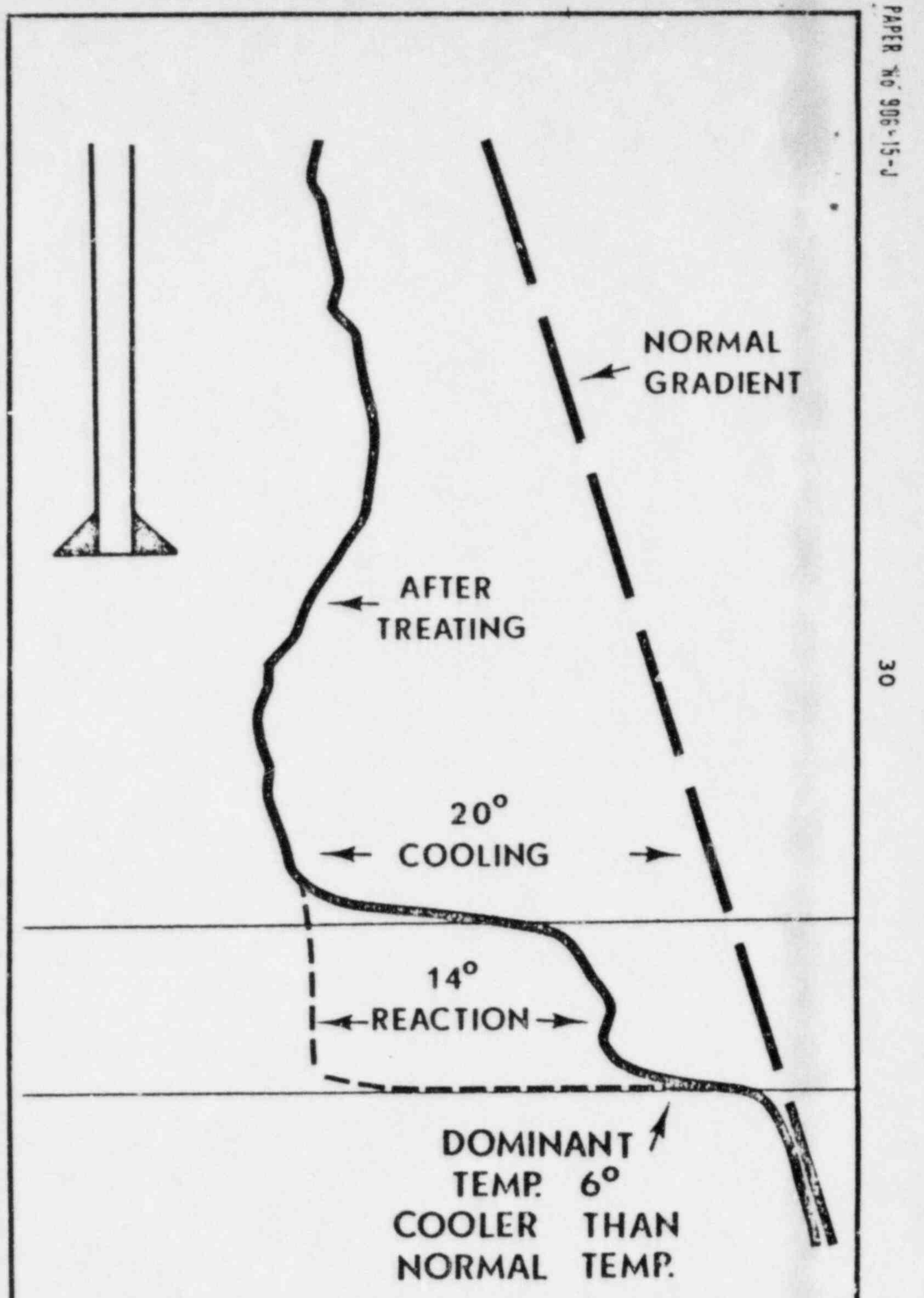
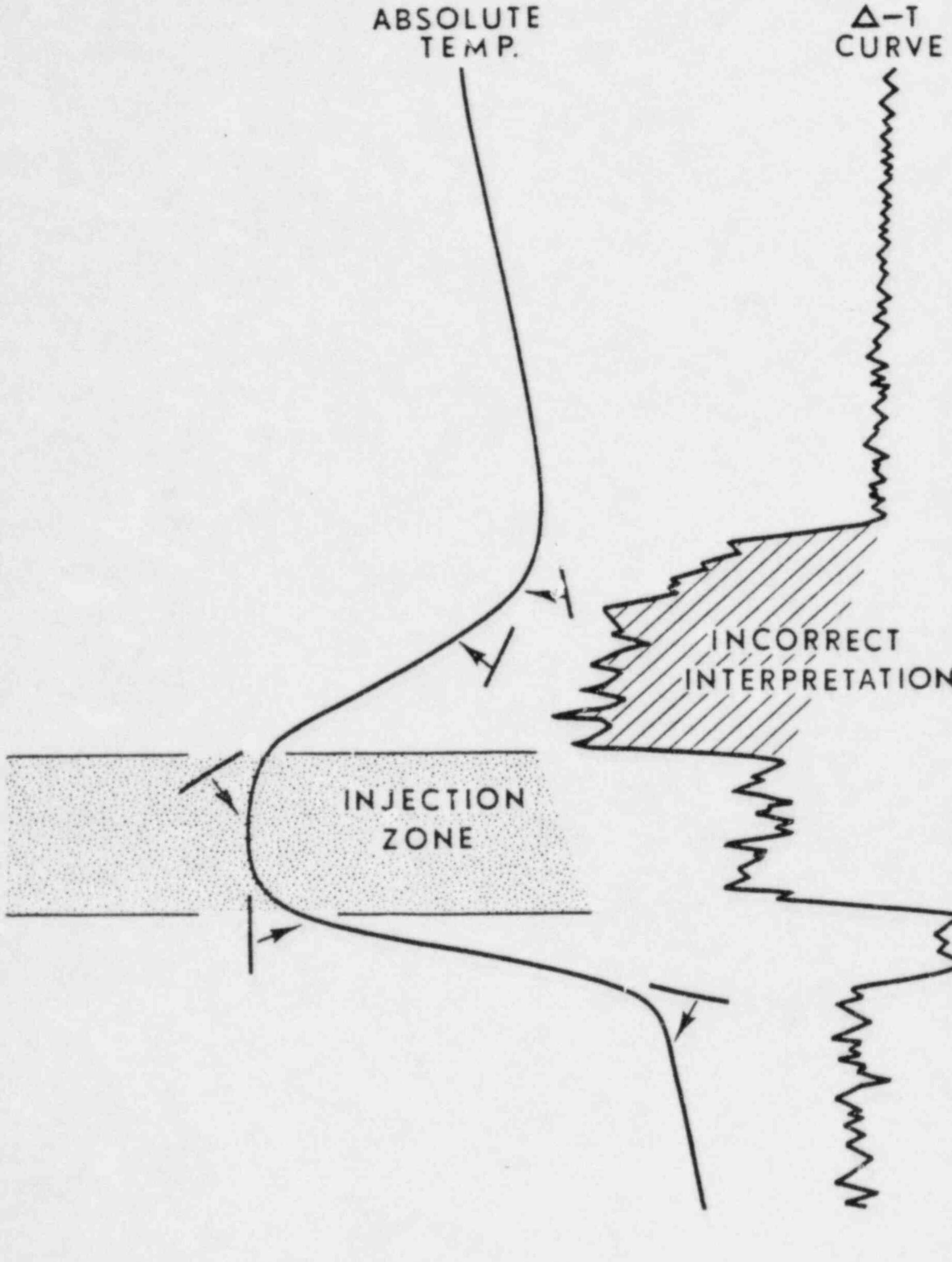


FIG. 17-B



INCORRECT USE OF
"DIFFERENTIAL" CURVE

FIG. 18

Exhibit F

GEOLOGY AND GEOHYDROLOGY STUDY

Structural Geology

The study area is located on the southwest flank of the Ozark Uplift. Regional dip is 2-3° southwest, except in the vicinity of faults. The Carlile School fault, one mile east of the storage well, was mapped on the surface with the aid of aerial photographs and confirmed by core holes. The core hole cross-section (Attachment 1) illustrates the contrast in the stratigraphic section on either side of the fault. There are other faults in the general area as shown on the regional structural map (Attachment 2). The location of these faults was determined from published maps and subsurface data. (Miser, 1954, Geologic Map of Oklahoma. Huffman, 1958, Oklahoma Geological Survey Bulletin #77). According to Huffman in Bulletin #77, the faulting is the result of tensional forces created during the uplift of the Ozark geanticline. This relatively mild tectonic activity ended by Middle De Moinesian time and the region has been structurally stable since then.

Stratigraphy

The youngest rocks exposed locally consist of a sandstone and shale sequence of the Lower Atoka. The outcropping Atoka rocks are approximately 100' thick and they are capped by a 15' thick terrace gravel in the immediate area of the plant site. Attachment 3 is a map of the Sequoyah Plant Site Area showing topography and approximate distribution of surface material. Outcrops are very poor, so it was necessary to rely primarily on core hole data in constructing the surface geological map.

The complete stratigraphic section (Attachment 4) penetrated in the storage well is as follows:

Formation	Thickness	Lithology	Character
Pennsylvanian Atoka	395'	Shale and sandstone	Non-porous, except for the basal Spiro sandstone from 342 to 373'. Contains salt-water.
Morrow	170'	Limestone and shale	Non-porous.
Mississippian	185'	Limestone and shale	Non-porous.

Formation	Thickness	Lithology	Character
Siluro-Devonian Hunton	240'	Dense limestone	Non-porous.
Ordovician			
Sylvan	40'	Shale	Non-porous.
Viola	50'	Dense limestone	Non-porous.
Simpson	250'	Sandstone and interbedded dense limestone	Sandstone is porous in part, contains salt-water.
Cambro-Ordovician Arbuckle	1620'	Dolomite	Dense to very porous. Contains saltwater.
Reagan	145'	Dolomitic sand-stone and sandy dolomite	Impermeable.

Cross-sections A-A' (Attachment 5) and B-B' (Attachment 6) show that there is very good lateral continuity of all subsurface units with the exception of the Atoka series. Electrical log correlations are very good for the pre-Atoka beds covering a broad area of Oklahoma and surrounding states. All of the sub-surface units thicken to the south and southwest and reach a maximum thickness in the general area of the Arbuckle Mountains in south central Oklahoma. In a northeasterly direction, approaching the crest of the Ozark Uplift, all stratigraphic units thin by onlap and truncation. For a detailed regional discussion, refer to Huffman, G. G., 1959, "Pre-De Moinesian Isopachous and Paleogelogic Studies in the Central Mid-Continent Region," AAPG Bulletin, Volume 43, pages 2541-2574.

Arbuckle Group - Proposed Injection Horizon

The Arbuckle is a carbonate sequence, dominantly dolomite, with minor shale and chert. It is 1765' thick at the well site, including the basal Reagan sandstone, and reaches a maximum thickness of 7000' in the Arbuckle Mountains. Northeast of the well site, the Arbuckle thins to about 180' at the outcrop of the Cotter dolomite (uppermost Arbuckle) near Spavinaw, Delaware County, Oklahoma (Huffman 1958). The distribution of the Arbuckle group is very wide-spread, being recognized throughout the Mid-Continent region (Huffman 1959).

Rocks of the Arbuckle group vary in character from dense and impermeable to very porous and permeable. In general, the upper part of the Arbuckle is essentially non-porous, the Middle

Arbuckle is characterized by alternating beds of porous and non-porous dolomite and the lower one-third of the section is characterized by thick zones of high order porosity. Measured porosity values of Arbuckle dolomite range from less than 2% to as high as 20%. Permeability ranges from less than 0.1 millidarcy to a high of 768 millidarcies. Porosity-permeability relationships indicate that porosities less than 3% are non-effective. Correlations of the zones of good porosity development are reasonably good throughout the area (see electric log cross-sections, Attachments 5 and 6). Porosity values for the Arbuckle formation were established by a foot-by-foot analysis of the Schlumberger Formation Density Log (Attachment 7) and from the core analysis (Attachment 8). The depths of the five intervals with the highest permeability were derived from the injectivity test data. See Figure 3, Exhibit A. Average porosity values were assigned to each layer and the thickness of the net effective porosity was determined by using a minimum value of 3% as a cut-off. The average porosity ranges from a low of 5.8% for layer #5 to a high of 9.9% for layer #4. The total net effective porosity for the five permeable layers is 116 feet.

It should be noted that both the density log and the Neutron Porosity Log were calibrated for a limestone formation with an assumed constant grain density of 2.71 grams/cc. Since the Arbuckle formation is in fact made up of alternate layers of porous and dense dolomite with a measured average grain density of 2.81, it is necessary to apply a correction to the density curve before computing porosity values. Since the logs were calibrated for limestone, the porosity scale printed on the Neutron Porosity Log cannot be used with accuracy. The error in the apparent porosity resulting from the limestone calibration ranges from two to as high as eight percentage points.

The chemical and physical characteristics of the Arbuckle formation water is given in the water analysis submitted by the Halliburton Company (Attachment 9). Specific gravity is 1.104 at 75°F, pH is 7.0 and resistivity is 0.093 ohms/M^2/M. Total dissolved solids are 142,000 ppm and the chloride content is 88,300 ppm. Reservoir temperature is 126°F as reported by Schlumberger and the reservoir fluid pressure is 1238.45 psi at an elevation of 2071 ft. below sea level. The lithostatic pressure at the base of the Arbuckle (3100') is calculated to be 3490 psi by using a mean density of 2.60 for the overlying rock column. Fracture pressure is estimated by Halliburton Services at 70% of lithostatic or 2440 psi.

The confining bed underlying the Arbuckle consists of impermeable granite. The confining beds above the proposed injection horizon consist of 170' of dense shaley Arbuckle dolomite and 110' of dense Arbuckle limestone. This Arbuckle "caprock" is in turn overlain by a 1300' thick sequence of dense shale, siltstone,

sandstone and limestone. These non-porous beds will effectively prevent the vertical migration of injected fluid.

Groundwater Geohydrology

Information on the geohydrology of the fresh water aquifers at the Sequoyah plant site and vicinity has been taken primarily from:

> Oklahoma Geological Survey Hydrologic Atlas #1 - 1969 "The Water Resources of the Ft. Smith Quadrangle, by M. V. Marcher.

Marcher states that, in general, the Atoka formation is a very poor aquifer. Water quality is poor and yields range from a fraction of a gallon per minute to a few gallons per minute. The best water well in the plant site area is located in the NW NW/4 of Section 27 12N 21E. Depth of the hole is 84', static water level is 29' and yield is 1 gpm. Water quality of this well is better than average for the Atoka formation, with total dissolved solids of approximately 460 ppm. The erratic occurrence of fresh water locally is the result of meteoric water being trapped in fractured shale and constitutes a "perched" water table at an elevation approximately 40' above the water level of the alluvial aquifer of the Arkansas River.

The Arkansas River alluvium is a good aquifer with reported yields as high as 900 gpm. The water is "hard to very hard" (Marcher 1969), but is suitable for irrigation. A typical alluvium water well is located in the SE SE/4 of Section 19 12N 21E. Marcher reports a depth of 44', static water level at 4' and a yield of 400 gpm.

Mineral Resources

The only mineral resource in the immediate area of the well site is a limited amount of terrace gravel. Sandstone has been quarried at two locations approximately one mile north of the well site and sand has been dredged from the flood plain of the Illinois River two miles to the north. Sand has also been dredged from the Arkansas River two miles west of the plant. Nearest gas production is 14 miles west, at the town of Warner. Coal is being mined from a depth of 1400' at Stigler in Haskell County, 18 miles south of the well site. Nearest coal deposits are located about 12 miles southeast of the plant site, but the mines are currently inactive.

Seismicity

As previously stated, Huffman (1958) considers the area under discussion to have been tectonically stable since Middle De Moinesian time. This conclusion is supported by the Coast and

and Geogetic Survey Report 41-1 (revised) "Earthquake History of the United States". The report lists minor to moderate seismic activity in the El Reno area, west of Oklahoma City, the Tulsa area and in the Ouachita Mountains of southeastern Oklahoma and west central Arkansas. The earthquake epicenter nearest the well site is near Poteau, Oklahoma, 40 miles to the south. This earthquake of April 27, 1961, is listed at intensity V on the Modified Mercalli scale (very minor damage to dishes and windows). All of the listed earthquakes appear to be associated with structural features outside of the southwest Ozark tectonic province (Tectonic Map of United States, USGS and AAPG 1961). It is concluded that earthquakes do not constitute a significant hazard at the Sequoyah well site.

ATTACHMENT 8
Exhibit F

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

October 28, 1969

REPLY TO
8 N. W. 42ND ST.
OKLAHOMA CITY, OKLA.
73118

Kerr-McGee Corporation
705 Kerr-McGee Building
Oklahoma City, Oklahoma 73102

Attn: Mr. Tom C. Danie

Subject: Core Analysis
Sequoyah Factory Waste
Disposal No. 1 Well
Sequoyah County, Oklahoma
CLI File No. CP-1-7049

Gentlemen:

The Arbuckle Formation was diamond cored in the subject well at various intervals from 1451 to 3032 feet. The core was preserved at the well-site and transported to the Oklahoma City Laboratory for analysis by whole core methods. The analysis results are presented in tabular form on the accompanying page of this report.

Grain Density measurements were requested at scattered intervals and appear along with the tabular data.

Thank you for this opportunity to be of service.

Yours very truly,

CORE LABORATORIES, INC.

J. G. Evertson

J. G. Evertson, Jr.
District Manager

JGE:sh
5cc: Addressee

CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company KERR-MCGEE CORPORATION Formation ARBUCKLE File CP-1-7049

Well SEQUOYAH FACTORY WASTE DISPOSAL #1 Core Type DIAMOND Date Report 10-28-69

Field ____ Drilling Fluid WATER BASE MUD Analysts BOYLE

County SEQUOYAH State OKLAHOMA Elev. 579' KB Location 997' FEL & 3231' FSL, SECTION 21-12N-21E

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS		POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE		SAMPLE DESCRIPTION AND REMARKS
		PERM. MAX.	PERM. 90°		OIL	TOTAL WATER	
	WHOLE CORE ANALYSIS						
1	1451.2-52.1	4.0	3.4	9.5	0.0	89.1	Dol, vuggy, vert frac
2	52.1-53.0	0.1	<0.1	7.7	0.0	92.9	Dol, vert frac
3	53.0-54.5	0.1	0.1	9.9	0.0	91.6	Dol, few pp vugs
4	54.5-55.5	0.2	0.1	11.2	0.0	89.6	Dol, sl/vuggy
5	55.5-57.0	0.3	0.1	12.4	0.0	91.5	Dol, pp vugs
6	57.0-58.0	<0.1	<0.1	5.9	0.0	93.3	Dol, sl/shy, few pp vugs
7	58.0-59.0	<0.1	<0.1	11.0	0.0	92.2	Dol, pp vugs
8	59.0-60.0	0.7	0.6	8.5	0.0	87.8	Dol, few pp vugs
9	60.0-61.2	2.3	1.9	10.7	0.0	90.0	Dol, few pp vugs
10	61.2-62.0	1.2	1.1	12.1	0.0	87.7	Dol, few pp vugs, sl/cherty
1	62.0-63.5	1.5	1.3	13.4	0.0	88.5	Dol, few pp vugs
12	63.5-65.3	0.1	0.1	9.4	0.0	88.9	Dol, few pp vugs
13	65.3-66.8	<0.1	<0.1	5.1	0.0	91.4	Dol, sl/shy
14	66.8-68.2	<0.1	<0.1	3.7	0.0	89.3	Dol, sl/shy
15	68.2-69.5	<0.1	<0.1	3.4	0.0	90.6	Dol, sl/shy
16	69.5-70.6	<0.1	<0.1	4.4	0.0	93.4	Dol, sl/shy
17	70.6-71.7	0.1	<0.1	4.9	0.0	91.8	Dol, vuggy
18	71.7-73.3	0.1	<0.1	3.7	0.0	89.2	Dol, vuggy
19	73.3-74.4	0.1	0.1	8.2	0.0	91.5	Dol, few pp vugs
20	74.4-76.0	0.1	<0.1	6.8	0.0	97.2	Dol, shy
21	76.0-77.0	<0.1	<0.1	4.9	0.0	85.9	Dol, few pp vugs
	1477.0-1737.0						Drilled
22	1737.0-38.7	<0.1*		3.3	0.0	76.7	Dol, sl/shy, few pp vugs
	38.7-43.0						Lost core
	1743.0-1912.0						Drilled
23	1912.0-13.0	<0.1	<0.1	2.1	0.0	67.4	Dol, sl/vuggy
23	13.0-14.2	<0.1	<0.1	1.9	0.0	33.3	Dol
25	14.2-15.7	<0.1	<0.1	1.4	0.0	50.0	Dol, sl/cherty
26	15.7-16.7	<0.1	<0.1	1.9	0.0	47.6	Dol
27	16.7-18.3	<0.1	<0.1	2.4	0.0	39.8	Dol, sl/cherty
28	18.3-19.7	<0.1	<0.1	2.4	0.0	34.8	Dol
29	19.7-21.0	<0.1	<0.1	2.3	0.0	33.3	Dol
30	21.0-21.7	<0.1	<0.1	0.9	0.0	64.3	Dol, shy
31	21.7-23.3	<0.1	<0.1	3.1	0.0	46.9	Dol
32	23.3-24.2	<0.1	<0.1	1.4	0.0	41.9	Dol, sl/shy
	1924.2-2294.0						Drilled
33	2294.0-95.6	101	24	9.8	0.0	64.6	Dol, vuggy, sl/cherty
34	95.6-96.6	0.1*		9.0	0.0	69.1	Dol, vuggy, vert frac
35	96.6-98.0	768	1.8	9.6	0.0	67.3	Dol, vuggy
36	98.0-99.4	30	0.2	9.2	0.0	69.8	Dol, vuggy, vert frac

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File CP-1-7049 Page No. 2
Well Sequoyah Factory Waste Disposa No. 1

CORE ANALYSIS RESULTS

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS MAX.	90°	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
37	2299.4-01.2	2.0	1.9	9.5	0.0	69.0	Dol, vuggy, vert frac
38	2301.2-02.8	0.8	0.4	6.9	0.0	68.5	Dol, vuggy
39	02.8-03.8	0.1*		5.2	0.0	73.6	Dol, vuggy, vert frac
40	03.8-05.2	22	0.2	6.7	0.0	75.1	Dol, vuggy, vert frac
41	05.2-06.5	1.1	0.9	4.3	0.0	76.4	Dol, vuggy
42	06.5-07.9	0.6	0.3	6.6	0.0	76.4	Dol, vuggy
43	07.9-09.4	0.2	0.1	3.4	0.0	86.4	Dol, pp vugs, cherty
44	09.4-11.0	1.0	0.9	5.9	0.0	77.2	Dol, pp vugs, sl/cherty
	2311.0-12.0						Lost core
	2312.0-3021.0						Drilled
45	3021.0-22.4	0.2	0.1	5.3	0.0	76.4	Sd, dol
46	22.4-23.2	0.5	0.2	5.2	0.0	78.6	Sd, dol
47	23.2-24.8	0.2	0.1	2.8	0.0	86.4	Sd, dol, sty
48	24.8-26.6	0.1	0.1	6.1	0.0	67.5	Sd, dol, sty
49	26.6-28.4	0.3	0.1	3.1	0.0	85.4	Sd, dol, sty
50	28.4-29.7	0.2	0.1	3.7	0.0	80.9	Dol, sl/sdy, vuggy
51	29.7-31.5	0.8	0.7	4.4	0.0	72.6	Dol, vuggy, vert frac
	3031.5-32.0						Lost core

	GRAIN DENSITY
1452-53	2.808
1455-56	2.769
1457-58	2.762
1459-60	2.815
1462-63	2.845
1464-65	2.799
1466-67	2.798
1469-70	2.793
1471-72	2.833
1474-75	2.840
1476-77	2.837
2294-95	2.817
2298-99	2.818
2303-04	2.808
2307-08	2.800
2310-11	2.794
3021-22	2.706
3024-25	2.693
3028-29	2.822
3031-31.5	2.827

*DENOTES PLUG PERMEABILITY

THIS IS THE FINAL REPORT.

STEVENS BINDERY CO. - OKLA. CITY - 9/9

ATTACHMENT 9
Exhibit F

HALLIBURTON DIVISION LABORATORY
OKLAHOMA CITY, OKLAHOMA
HALLIBURTON COMPANY

FIELD LABORATORIES MAINTAINED AT VARIOUS POINTS IN THE OIL FIELDS

LABORATORY WATER ANALYSIS

Date November 24, 1969

Report No. WA2-11-69

To Kerr-McGee Corp.
Oklahoma City, Oklahoma

Submitted By ______ Date Received November 12, 1969

Well No. #1 Sequoyah Facility Depth not given Formation not given

Location Sequoyah County Oklahoma Section ______ Township ______ Range ______

Specific Gravity	1.104 @ 75 F.	
pH	7.00	
Total Dissolved Solids	142,000	Parts per Million*
Calcium (Ca)	11,300	Parts per Million
Magnesium (Mg)	2,470	Parts per Million
Chlorides (Cl)	88,300	Parts per Million
Sulfates (SO^4)	120	Parts per Million
Carbonates (CO^3)	0	Parts per Million
Bicarbonates (HCO^3)	159	Parts per Million
Total Iron (Fe)	22	Parts per Million
Sodium (Na)	39,700	Parts per Million

Remarks: R_w 0.095 @ 75 F.. Ohms/M

*Parts per million, by weight, uncorrected for Specific Gravity.

cc: Mr. D. G. Moriarty

Respectfully submitted,

HALLIBURTON COMPANY

By Wirt Davis
Division Chemist

NOTICE: This report is limited to the described sample tested. Any user of this report agrees that Halliburton shall not be liable for any loss or damage, whether due to act or omission, resulting from such report or its use.